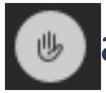
Workshop on Track 1 Proposals in R. 23-10-011

Energy Division Workshop

February 14, 2024

California Public
Utilities Commission

Logistics

- All attendees have been muted.
- To ask questions, please "raise your hand"  and a moderator/presenter will unmute you so you can ask your question.
- If you would rather type, use the Q + A function and send to "all panelists". Q + A questions will be read aloud by moderators/presenters; attendees may be unmuted to respond to the answer verbally.

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Participant List

Chat

Audio Options

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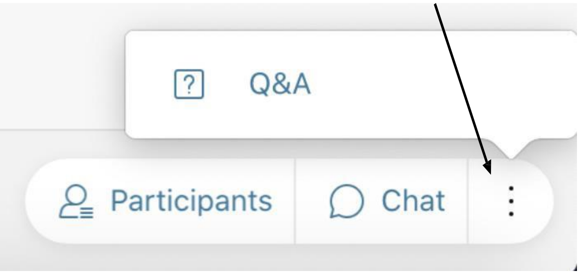


Background

- On December 18, 2023, the Commission issued a Scoping Memo establishing the issues to be addressed in Track 1 (of 3) of the RA Rulemaking (R.23-10-011) including the 24-Hour Slice-of-Day (SOD) Framework, the SOD Planning Reserve Margin (PRM), Unforced Capacity Methodology (UCAP), Demand Response (DR) Load Impact Protocols (LIP) Simplification, RA Compliance and Penalties, and other time-sensitive issues that can be implemented in time to impact the 2025 compliance year, including refinements to the Central Procurement Entity (CPE) structure.
- On January 19, 2024, 15 parties filed proposals and PG&E filed a Report on behalf of the LIP Simplification Working Group. On February 5, 2024, the ED issued its Report on the SOD Framework.
- On February 14, 2024, ED hosted a workshop on ED and Parties’ proposals; however, due to time constraints, that workshop did not cover all items on the agenda. This workshop is scheduled to discuss the remaining topics.

Agenda: February 28, 2024

1.	Welcome and Introductions	Energy Division	1:00	1:10
2.	Residual Capacity Auction	CalAdvocates	1:10	2:00
3.	RA Compliance and Penalty Structure, RA Import Bidding Rules	CalCCA	2:00	2:45
4.	Reversing the Revisions to DR Rules in D.23-06-029	CEERT	2:45	3:05
5.	Break		3:05	3:15
6.	Other Topics Requiring Additional Discussion (e.g., PRM, etc.)	All	3:15	4:30
7.	Next Steps, Adjourn	Energy Division	4:30	4:45

Agenda February 14, 2024

1.	**Welcome and Introductions**	**Energy Division (ED)**	**9:30am**	**9:35am**
2.	SOD Report	ED and CEC	9:35	10:15
3.	Long Duration Storage in SOD Framework	Form Energy	10:15	10:30
4.	Proposes change to the RA QC Counting Methodology for Hybrid and Co-Located Resources, Reflecting the 24-Hour SOD Energy Sufficiency Verification	CESA	10:30	10:45
5.	Import Allocation Rights, Imported Resource-Specific Solar And Wind Resources, and RA Requirements.	PG&E	10:45	10:55
6.	SOD PRM Calibration	ED	10:55	11:40
7.	Monthly PRM and Stress Testing Proposal	ACP	11:40	12:05
8.	PRM Calculation proposal	WPTF	12:05	12:10
9	RA SOD Transactability Proposal	CalCCA	12:10	12:30
10	Lunch		12:30	1:30

	Agenda, Continued			
11.	UCAP	ED	1:30	2:00
12.	UCAP, and Using the PCIA market price Benchmark to Determine Substitution Capacity Costs when Using PCIA-Eligible Resources.	PG&E	2:00	2:25
13.	LSEs Receiving Credits for "Effective PRM" Capacity on CAISO Supply Plans	AReM	2:25	2:35
14.	COD requirement and the MA RA compliance deadline; Proposing a System-wide Test Before Assessing LSEs; and Using the CAISO backstop and the higher of system and local RA penalties	CESA	2:35	2:50
15.	Allow Imports Without a Specific Generator	BPA	2:50	2:55
16.	Residual Capacity Auction	Pub Adv	2:55	3:25
17.	RA Compliance and Penalty Structure Proposals, and an RA Import Bidding Rules Proposal	CalCCA	3:25	3:55
18.	Consider reversing some of the changes to DR rules in D.23-06-029	CEERT	3:55	4:05
19.	CPE soft price proposal	WPTF	4:05	4:10
20.	Next Steps, Adjourn	ED	4:10	4:20

Energy Division Proposals

Slice of Day Report, Updates, and Next Steps

Background

- In April 2023, the Commission approved D.23-04-010, which resolved remaining RA Reform issues and adopted implementation details for the 24-hour Slice of Day (SOD) Framework, including compliance tools, resource counting rules, and a methodology to translate the planning reserve margin (PRM) to the SOD Framework.
- In accordance with the Decision, ED Staff developed, published, and solicited informal party feedback on the adopted tools throughout 2023. In addition, ED Staff provided a final opportunity for informal comments on the latest versions of the tools and other topics related to SOD implementation in December 2023.
- Further, the Decision directed Energy Division to prepare a report summarizing comments and feedback after the Year Ahead test showings. This report was submitted to the R.23-10-011 service list on February 5, 2024.

Topics Covered in Slice of Day Report

- LSE Showing Tool
- Load forecast process
- PRM Calibration Tool
- Master Resource Database
- Solar/wind exceedance
- Year Ahead test filings analysis

LSE Showing Tool Updates

LSE Showing Tool – Functional Changes

- Implemented Energy Only (EO) rules:
  - EO resources do not contribute toward system capacity requirements
  - Shown EO resource capacities are subtracted from charging needs in Storage Excess Capacity tests
- Applied showing year from Certification sheet when looking up requirements and allocations
- Removed Resource NQC sheet and moved information to Resource Database sheet
- Overhauled storage optimization framework
  - Implemented custom optimization algorithm; no longer uses Solver
  - Incorporated interconnection limits into constraints
  - Improved status indicators and provided user-configurable parameters

LSE Showing Tool – Additional Changes

- Fixed various errors in several queries
- Added LSE Full Name and Signature fields in Certification sheet
- Minor formatting and user feedback changes throughout
- Added scripts to help clear data from workbook and reload data from a Master Resource Database file
- Updates to accompanying User's Guide reflecting all changes
- See Changelog at the end of the User's Guide for full descriptions of changes

LSE Showing Tool – Next Steps

- Rev 26 expected to be transmitted to LSEs by mid-February
- This template should be used for any compliance-related energy sufficiency showings (April Month Ahead) until further notice/revisions
- The next test showing is due on March 1 (March Month Ahead)

Load Forecast Process/RA 2025 Demand Forecasting

Lynn Marshall, Energy Assessments Division, CEC

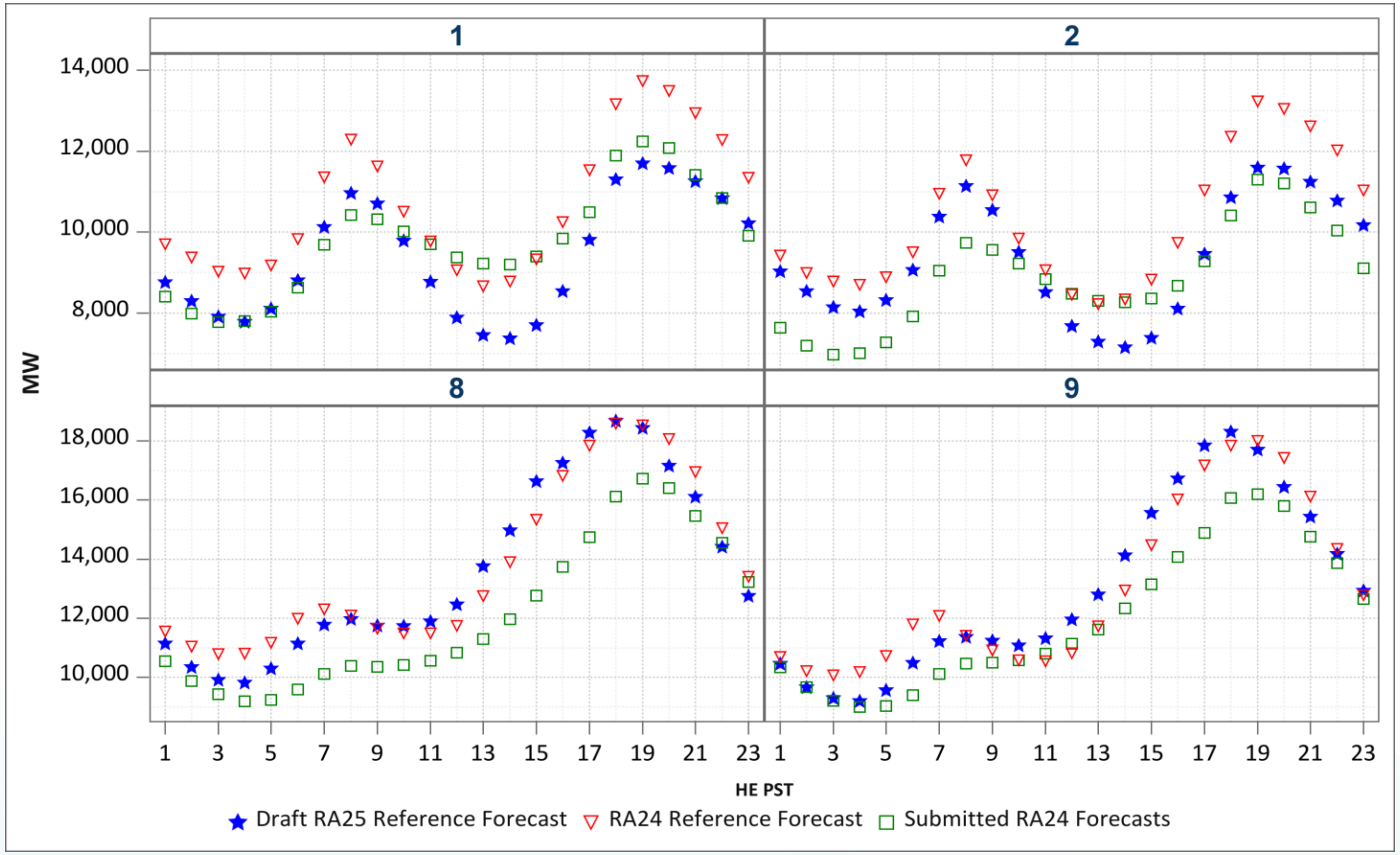
RA 2025 Reference Forecast

- CED 2023 Planning forecast
  - Significant changes to hourly load forecast model, leading to changes in peak and shape.
- Jurisdictional forecast shown today is draft, using CEC pumping load forecast and RA 2024 data to estimate POU share of PGE and SCE TACs.

CED 2023 Planning Scenario, IOU Service Area Peaks coincident with CAISO system peak												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PGE	11,698	11,586	11,588	12,541	14,867	18,596	19,128	18,672	17,842	14,422	11,794	12,085
SCE	11,854	11,634	11,845	12,573	13,900	16,658	19,600	18,656	20,073	15,814	13,160	11,947
SDGE	3,007	2,901	2,799	2,885	2,551	3,104	3,416	3,391	4,131	3,526	3,259	2,967
Total	26,558	26,121	26,232	27,999	31,318	38,358	42,144	40,719	42,046	33,761	28,213	26,999
Change from RA 24 at system peak												
PGE	(2,041)	(1,661)	(537)	(807)	(1,008)	202	189	72	(161)	(405)	(741)	(2,038)
SCE	(919)	(896)	(538)	(1,251)	(1,155)	(439)	391	(904)	(799)	(1,021)	(313)	(1,421)
SDGE	(304)	(373)	(306)	(240)	(747)	(275)	(175)	(654)	(220)	(233)	(136)	(475)
Total	(3,265)	(2,930)	(1,381)	(2,298)	(2,910)	(511)	404	(1,486)	(1,181)	(1,658)	(1,190)	(3,934)

PG&E Service Area Forecast

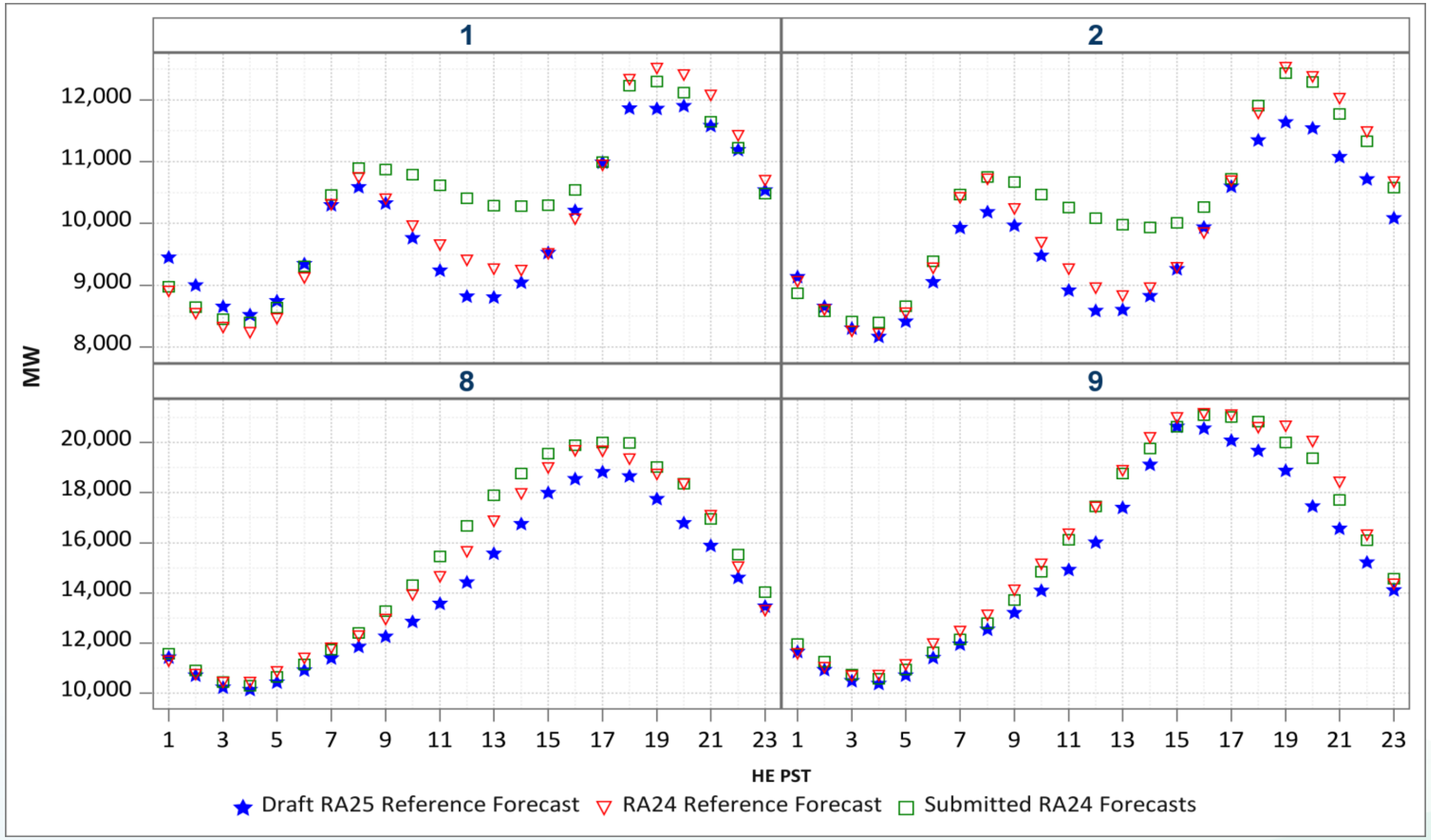
Select months for 2025



- Morning loads are lower than in CED 2022, but still have a higher morning peak than LSE forecasts.
- Gap should be allocated based on individual LSE loads to reduce pro-rata.

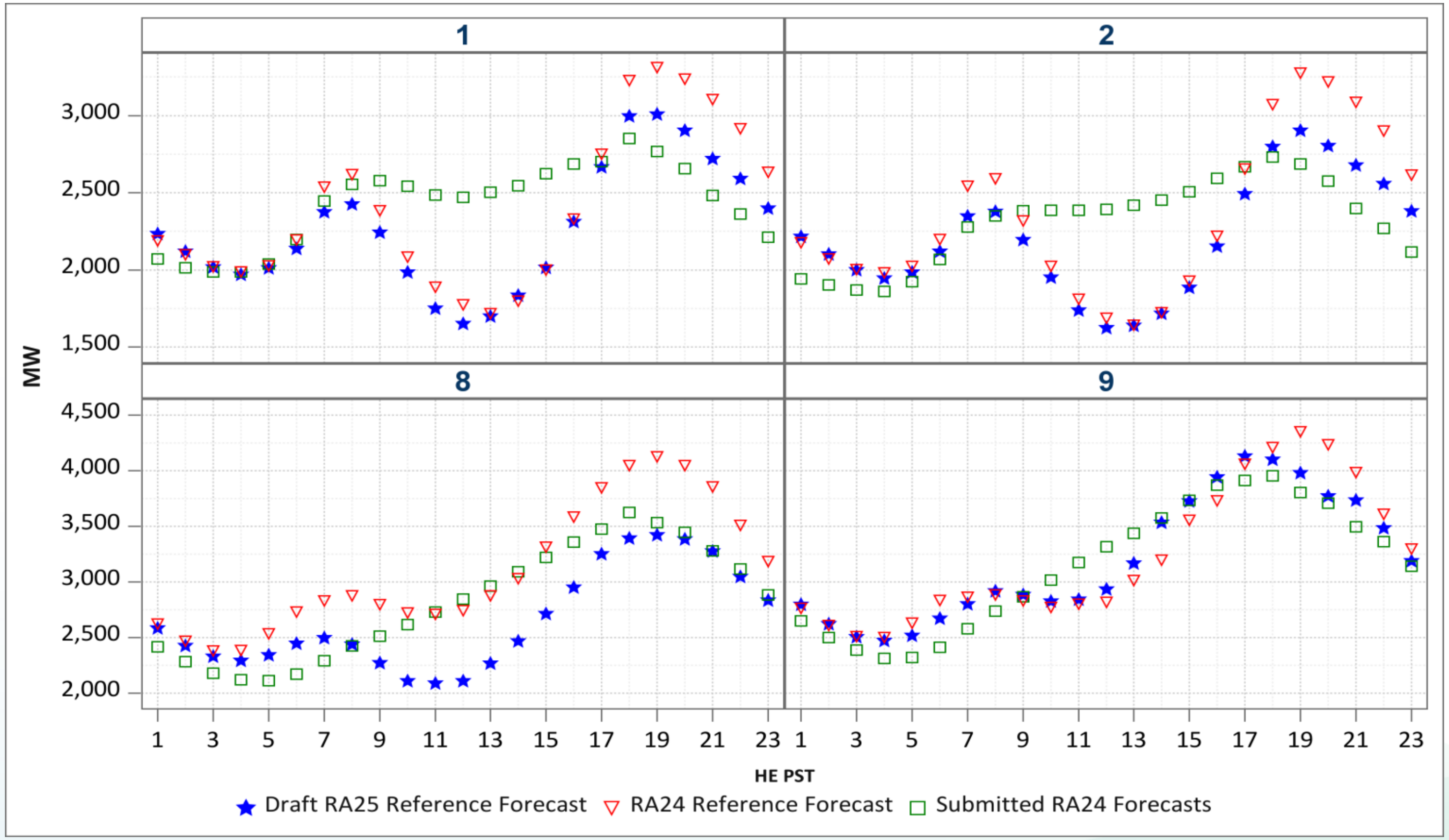
SCE Service Area Forecast

Select months for 2025



SDGE Service Area Forecast

Select months for 2025



Load Forecast Process Overview

- CEC first followed the existing process for monthly coincident peak forecast determination, then used that as input into hourly forecast development.
- Planned changes for 2025 in red

1) **Monthly peak process**:
   a) Develop reference forecast for IOU service areas and direct access
   b) Develop reference peak demand and peak-day energy estimate for LSEs based on available data. Evaluate need for LSE-specific adjustments.
      - Establish morning-hours peak and energy benchmarks for expected LSE loads.
   ~~c) Estimate and apply monthly system peak coincidence factors to LSE monthly peak forecasts~~. Estimate hourly coincident peak day load shape using historic loads; compare to LSEs submitted shape to derive coincidence adjustment.
   d) Apply adjustments for demand side credits.
   e) Apply pro-rata adjustments to bring the total of the forecasts to within 1% of the CEC service area forecast.

Load Forecast Process Overview

2) **Hourly Forecast Process**
   a) ~~Calculate hourly coincidence factors using historic loads, which account for differences between load shapes on system peak day and LSE's peak day.~~
   b) Apply curve-fitting formula to fit LSEs' submitted load shape to the adjusted noncoincident monthly peak and energy from 1)
      - Modify curve-fitting process for direct access or other LSEs with nonconventional load shapes
   c) Apply hourly coincidence adjustment; Calibrate to coincident peak hour forecast from 1) if needed.
   d) Apply hourly load modifier credit. This includes AAEE, LMDR, and in SCE, utility-owned storage. (negative in charging hours).
   e) Pro rata to within 1% of 2023 IEPR 1-in-2 hourly forecast for the monthly coincident peak day, by TAC.

LSE Forecast Distribution

- CEC plans to distribute draft individual adjusted demand forecasts to LSEs in early July:
  - Monthly coincident adjusted peaks
  - Hourly adjusted forecast detail
- Hourly shapes should be considered preliminary; LSEs may provide feedback to CEC

Next Steps – Load Forecast Process

- 2023 IEPR demand forecast is expected to be adopted today (February 14) at CEC's Business Meeting
- CEC and ED Staff will hold a workshop in Q1 2024 to discuss additional improvements to 2025 load forecast process
- LSEs are still scheduled to receive their initial adjusted hourly SOD forecasts in July 2024 and final hourly SOD forecasts in September 2024 for 2025 Compliance Year

Additional Updates/Next Steps

Master Resource Database

- MRD will continue to be updated on a monthly basis alongside the CAISO's monthly NQC process.
- ED Staff will continue to use default values unless otherwise notified—therefore, ED Staff expects that generators that seek to update their MRD fields provide ED Staff with this information ahead of being added to the NQC list (via CAISO's process) to ensure a timely process of updating the MRD list ahead of compliance showings
- Resources that are shown in RA filings but still under construction must be verifiable against the Generator Interconnection Resource ID report that stems from CAISO's New Resource Implementation (NRI) database
- LSEs may further notify generators if a value is misrepresented/inconsistent with a contract

Solar/Wind Exceedance

- ED Staff will update the exceedance profiles to use the latest six years of available CAISO settlement data (2018-2023) for the 2025 RA Compliance Year.

PRM Calibration Tool

- ED Staff's and stakeholders' proposals will be discussed at today's workshop
- Additional LOLE modeling will be conducted in early summer 2024 to guide calculation of 2026 SOD RA obligations

Overview of Year Ahead Test Filings

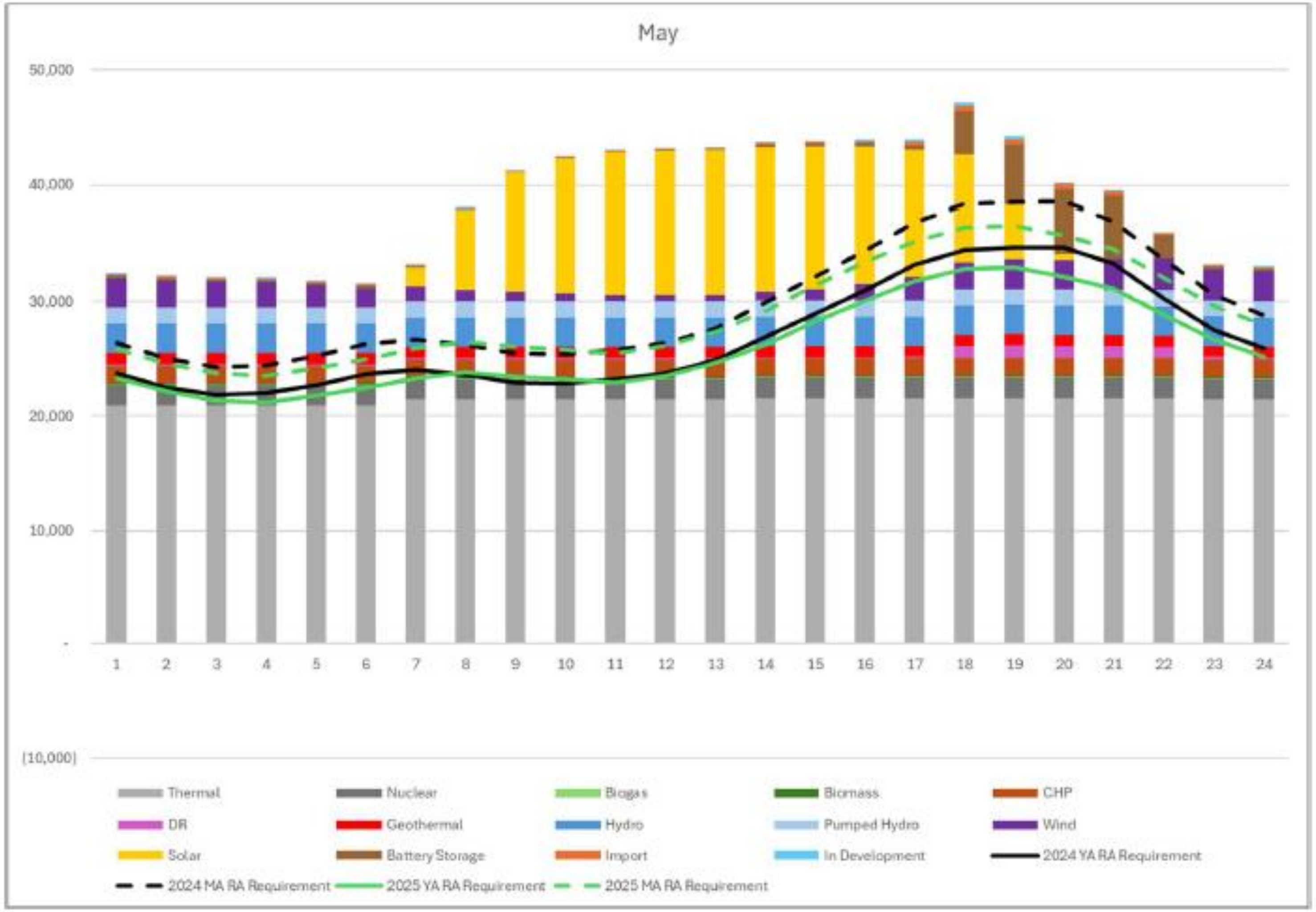
Background

- All 38 LSEs under the Commission's jurisdiction submitted SOD Year Ahead test showings.

- **Limitations of Analysis**
  - ED Staff asked LSEs to refile if resources appeared to be entered incorrectly in the templates, however, several issues were discovered later regarding entry of hybrid resources as well as some residual solar/wind scaling issues. These were manually fixed by ED Staff to the best of their ability.
  - ED Staff only looked at the hourly system capacity showings and compared them against requirements. ED Staff did not look at charging sufficiency or other validation checks within the templates.

- **Assumptions for 2025 RA Requirements**
  - 2025 RA requirements are estimated based on CED 2023, backing out 10% for non-CPUC-jurisdictional LSEs, another 10% for Year Ahead requirement, and applying a 17% PRM

Aggregate Showings – May



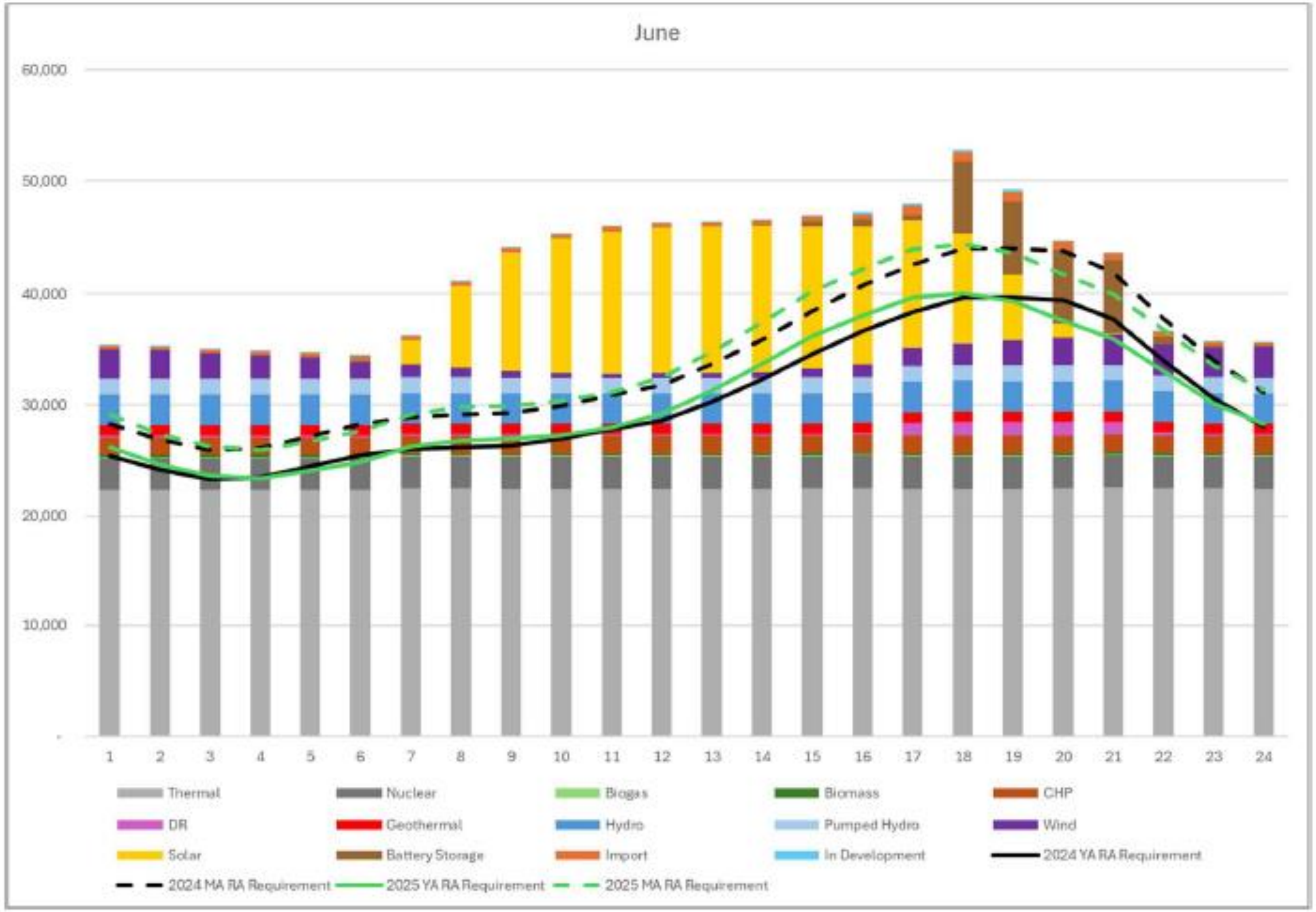
Aggregate Showings – May

May	Aggregate System Showings	2024 90% YA Requirement + 15.43% PRM	Aggregate Position	Aggregate Deficiencies
HE 1	32,459	23,721	8,738	(420)
HE 2	32,250	22,490	9,760	(350)
HE 3	32,105	21,834	10,270	(310)
HE 4	32,073	21,976	10,097	(316)
HE 5	31,822	22,695	9,127	(453)
HE 6	31,552	23,684	7,869	(572)
HE 7	33,236	24,016	9,219	(198)
HE 8	38,067	23,564	14,503	(101)
HE 9	41,286	22,907	18,379	(60)
HE 10	42,494	22,818	19,676	(82)
HE 11	43,024	23,191	19,834	(95)
HE 12	43,207	23,727	19,480	(111)
HE 13	43,281	24,857	18,424	(102)
HE 14	43,710	26,905	16,806	(118)
HE 15	43,802	28,937	14,864	(197)
HE 16	43,987	30,973	13,014	(226)
HE 17	43,988	33,156	10,832	(340)
HE 18	47,145	34,495	12,650	(120)
HE 19	44,236	34,685	9,550	(153)
HE 20	40,193	34,721	5,472	(362)
HE 21	39,517	33,257	6,260	(328)
HE 22	36,026	30,292	5,734	(572)
HE 23	33,231	27,519	5,712	(424)
HE 24	33,041	25,892	7,149	(248)

(estimated)

May	Aggregate System Showings	2025 Load Forecast + 17% PRM	Aggregate Position
HE 1	32,459	23,285	9,174
HE 2	32,250	22,130	10,120
HE 3	32,105	21,347	10,758
HE 4	32,073	21,192	10,880
HE 5	31,822	21,769	10,052
HE 6	31,552	22,426	9,126
HE 7	33,236	23,307	9,929
HE 8	38,067	23,777	14,290
HE 9	41,286	23,440	17,846
HE 10	42,494	23,193	19,301
HE 11	43,024	22,938	20,086
HE 12	43,207	23,492	19,715
HE 13	43,281	24,619	18,662
HE 14	43,710	26,203	17,507
HE 15	43,802	28,251	15,551
HE 16	43,987	30,047	13,940
HE 17	43,988	31,726	12,262
HE 18	47,145	32,792	14,353
HE 19	44,236	32,937	11,298
HE 20	40,193	32,151	8,043
HE 21	39,517	31,065	8,452
HE 22	36,026	28,867	7,160
HE 23	33,231	26,646	6,586
HE 24	33,041	25,126	7,915

Aggregate Showings – June



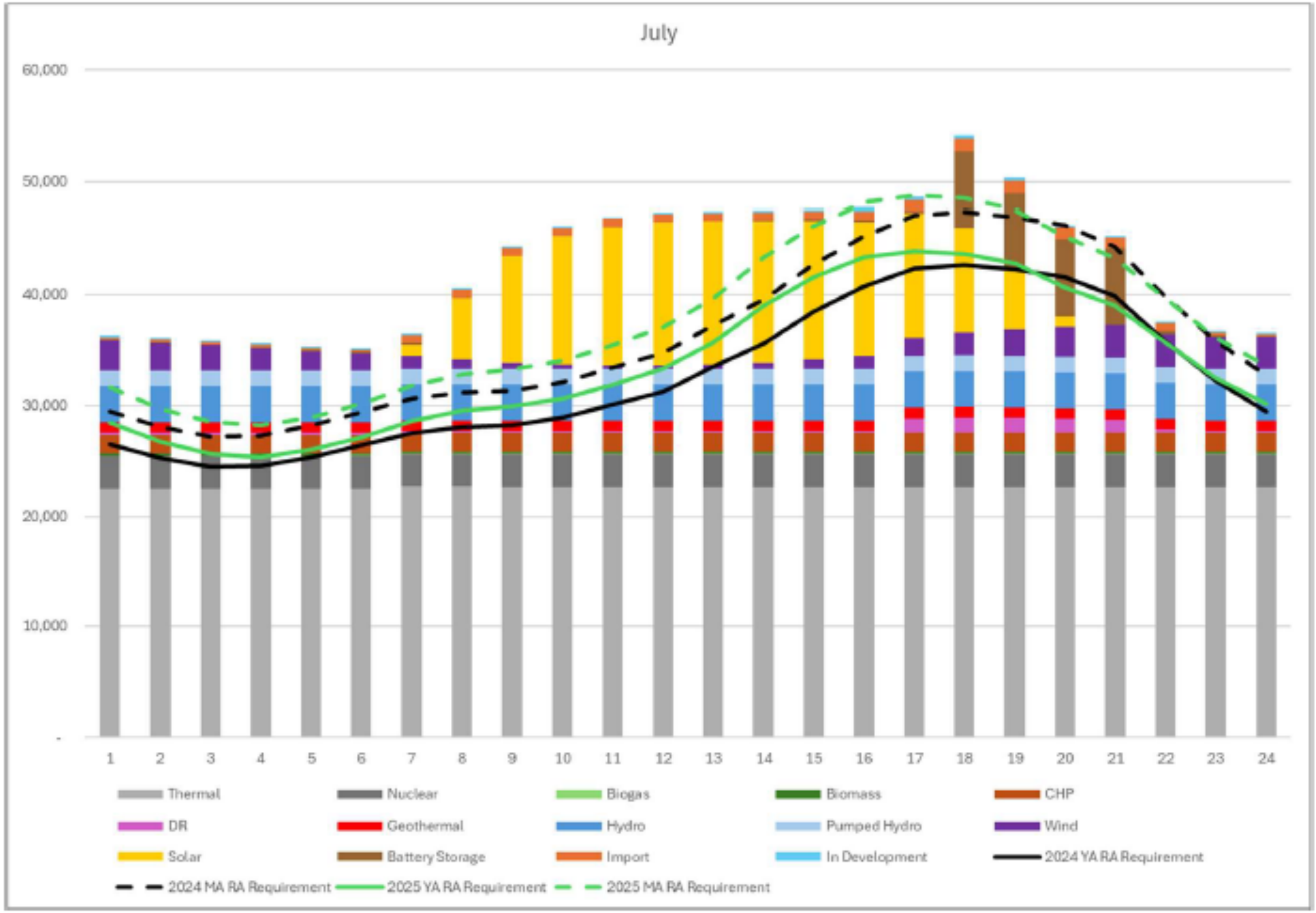
Aggregate Showings – June

June	Aggregate System Showings	2024 90% YA Requirement + 15.43% PRM	Aggregate Position	Aggregate Deficiencies
HE 1	35,462	25,451	10,011	(449)
HE 2	35,344	24,204	11,140	(359)
HE 3	35,094	23,361	11,733	(295)
HE 4	34,916	23,509	11,407	(324)
HE 5	34,753	24,474	10,278	(432)
HE 6	34,526	25,491	9,036	(564)
HE 7	36,331	26,017	10,314	(256)
HE 8	41,180	26,209	14,971	(108)
HE 9	44,197	26,357	17,840	(66)
HE 10	45,437	26,953	18,484	(77)
HE 11	46,093	27,824	18,269	(119)
HE 12	46,450	28,584	17,866	(133)
HE 13	46,511	30,343	16,168	(226)
HE 14	46,704	32,298	14,407	(314)
HE 15	47,059	34,570	12,489	(324)
HE 16	47,364	36,685	10,679	(323)
HE 17	47,983	38,351	9,633	(382)
HE 18	52,771	39,667	13,103	(284)
HE 19	49,209	39,679	9,530	(326)
HE 20	44,842	39,459	5,383	(552)
HE 21	43,753	37,742	6,011	(456)
HE 22	36,682	34,032	2,650	(743)
HE 23	35,771	30,626	5,145	(641)
HE 24	35,723	28,069	7,654	(412)

(estimated)

June	Aggregate System Showings	2025 Load Forecast + 17% PRM	Aggregate Position
HE 1	35,462	26,217	9,246
HE 2	35,344	24,632	10,712
HE 3	35,094	23,640	11,455
HE 4	34,916	23,401	11,515
HE 5	34,753	24,087	10,665
HE 6	34,526	24,921	9,606
HE 7	36,331	26,249	10,082
HE 8	41,180	26,822	14,358
HE 9	44,197	26,958	17,239
HE 10	45,437	27,315	18,122
HE 11	46,093	28,010	18,083
HE 12	46,450	29,247	17,203
HE 13	46,511	31,306	15,205
HE 14	46,704	33,704	13,001
HE 15	47,059	36,208	10,851
HE 16	47,364	38,027	9,337
HE 17	47,983	39,644	8,340
HE 18	52,771	40,057	12,714
HE 19	49,209	39,334	9,875
HE 20	44,842	37,587	7,255
HE 21	43,753	35,977	7,777
HE 22	36,682	33,115	3,567
HE 23	35,771	30,187	5,584
HE 24	35,723	28,284	7,439

Aggregate Showings – July



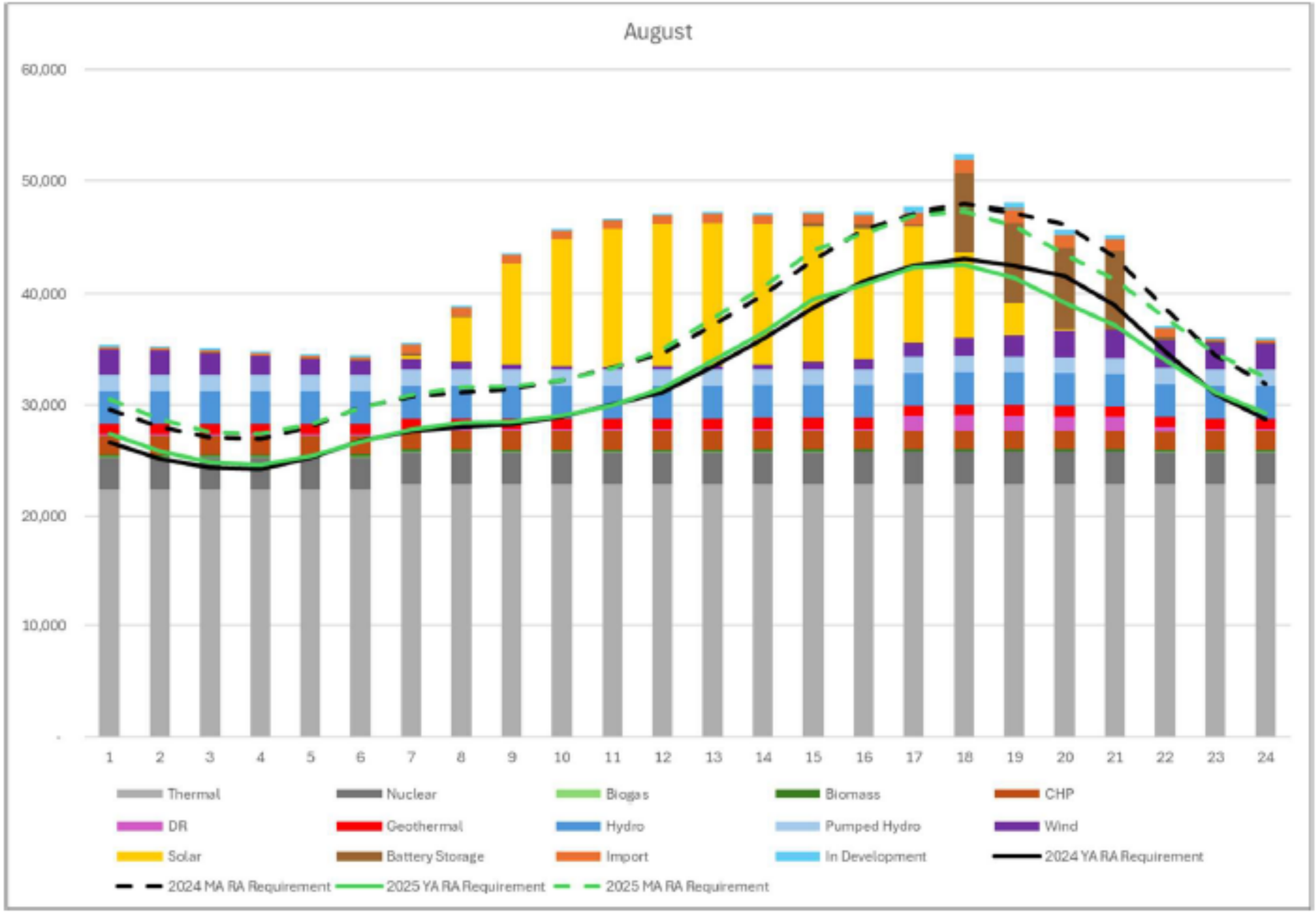
Aggregate Showings – July

July	Aggregate System Showings	2024 90% YA Requirement + 15.43% PRM	Aggregate Position	Aggregate Deficiencies
HE 1	36,302	26,538	9,763	(534)
HE 2	36,085	25,279	10,805	(439)
HE 3	35,874	24,536	11,338	(372)
HE 4	35,628	24,574	11,054	(398)
HE 5	35,346	25,402	9,944	(478)
HE 6	35,177	26,477	8,700	(558)
HE 7	36,473	27,551	8,921	(329)
HE 8	40,562	28,048	12,514	(175)
HE 9	44,292	28,202	16,090	(123)
HE 10	46,078	28,912	17,166	(172)
HE 11	46,898	30,116	16,782	(191)
HE 12	47,299	31,243	16,056	(233)
HE 13	47,411	33,500	13,911	(287)
HE 14	47,474	35,616	11,858	(330)
HE 15	47,530	38,427	9,103	(506)
HE 16	47,715	40,680	7,034	(512)
HE 17	48,676	42,329	6,347	(518)
HE 18	54,137	42,654	11,482	(382)
HE 19	50,374	42,222	8,152	(486)
HE 20	46,191	41,558	4,633	(725)
HE 21	45,229	39,820	5,409	(655)
HE 22	37,596	35,777	1,819	(949)
HE 23	36,723	32,240	4,483	(625)
HE 24	36,598	29,473	7,125	(410)

(estimated)

July	Aggregate System Showings	2025 Load Forecast + 17% PRM	Aggregate Position
HE 1	36,302	28,481	7,821
HE 2	36,085	26,727	9,358
HE 3	35,874	25,698	10,176
HE 4	35,628	25,401	10,227
HE 5	35,346	26,034	9,312
HE 6	35,177	27,140	8,036
HE 7	36,473	28,588	7,885
HE 8	40,562	29,516	11,045
HE 9	44,292	29,970	14,322
HE 10	46,078	30,626	15,452
HE 11	46,898	31,905	14,993
HE 12	47,299	33,343	13,956
HE 13	47,411	35,656	11,755
HE 14	47,474	39,006	8,468
HE 15	47,530	41,542	5,988
HE 16	47,715	43,307	4,407
HE 17	48,676	43,863	4,813
HE 18	54,137	43,666	10,470
HE 19	50,374	42,800	7,574
HE 20	46,191	40,650	5,541
HE 21	45,229	38,968	6,261
HE 22	37,596	35,646	1,950
HE 23	36,723	32,518	4,205
HE 24	36,598	30,201	6,397

Aggregate Showings – August



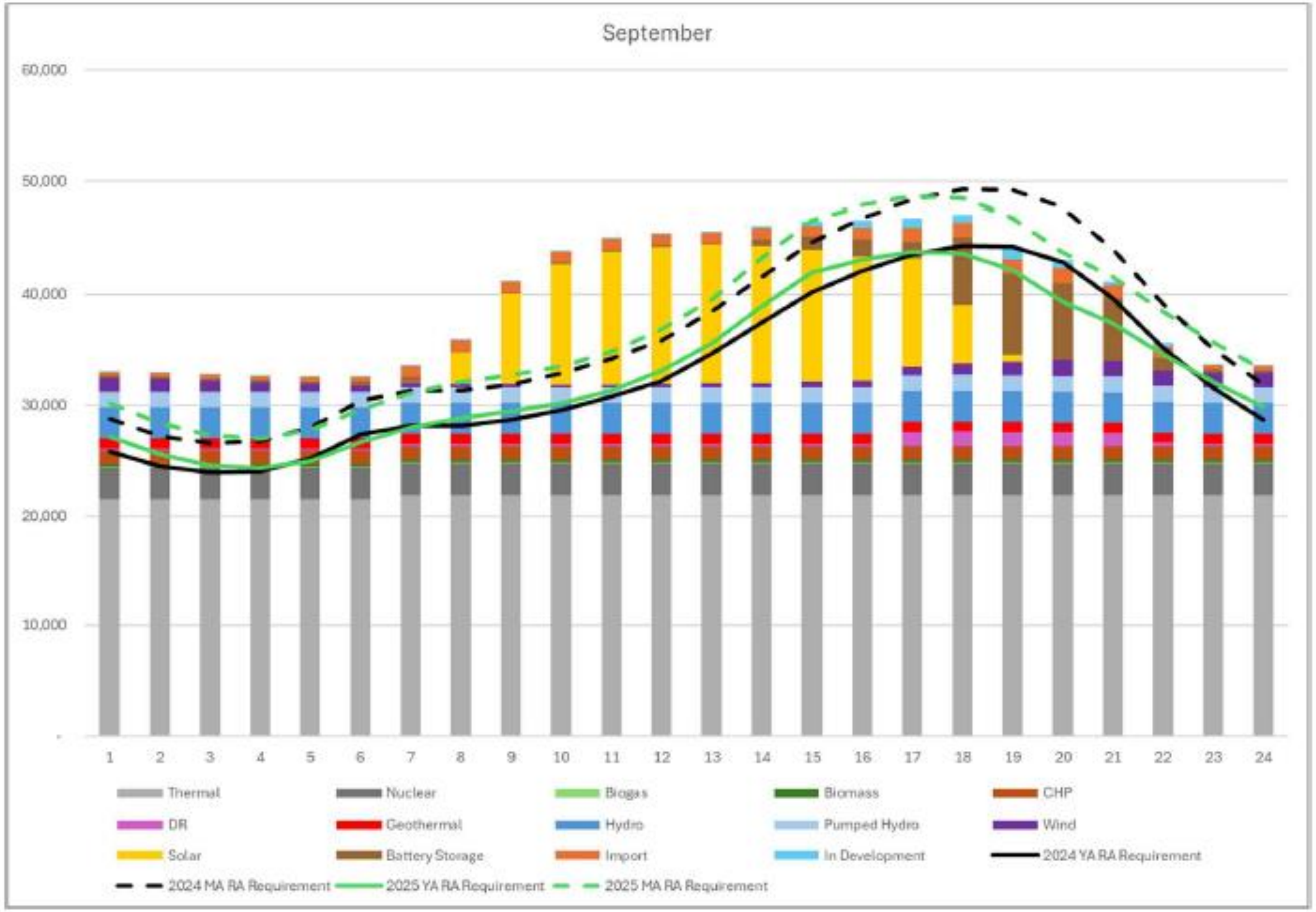
Aggregate Showings – August

August	Aggregate System Showings	2024 90% YA Requirement + 15.43% PRM	Aggregate Position	Aggregate Deficiencies
HE 1	35,452	26,660	8,792	(673)
HE 2	35,322	25,210	10,113	(536)
HE 3	35,125	24,377	10,747	(477)
HE 4	34,860	24,280	10,580	(465)
HE 5	34,598	25,258	9,340	(587)
HE 6	34,487	26,841	7,646	(784)
HE 7	35,634	27,689	7,945	(514)
HE 8	38,933	28,018	10,914	(306)
HE 9	43,648	28,273	15,374	(241)
HE 10	45,818	28,983	16,835	(217)
HE 11	46,763	30,058	16,704	(273)
HE 12	47,219	31,134	16,086	(323)
HE 13	47,347	33,457	13,890	(442)
HE 14	47,263	35,935	11,328	(545)
HE 15	47,345	38,696	8,649	(784)
HE 16	47,393	41,172	6,221	(893)
HE 17	47,652	42,495	5,158	(914)
HE 18	52,395	43,131	9,265	(791)
HE 19	48,084	42,533	5,551	(963)
HE 20	45,710	41,610	4,100	(1,220)
HE 21	45,258	38,956	6,302	(1,047)
HE 22	37,147	34,860	2,287	(1,256)
HE 23	36,146	31,009	5,138	(928)
HE 24	36,029	28,760	7,268	(670)

(estimated)

August	Aggregate System Showings	2025 Load Forecast + 17% PRM	Aggregate Position
HE 1	35,452	27,461	7,991
HE 2	35,322	25,841	9,481
HE 3	35,125	24,856	10,269
HE 4	34,860	24,653	10,207
HE 5	34,598	25,447	9,151
HE 6	34,487	26,758	7,729
HE 7	35,634	27,841	7,793
HE 8	38,933	28,468	10,465
HE 9	43,648	28,542	15,106
HE 10	45,818	29,036	16,782
HE 11	46,763	29,984	16,779
HE 12	47,219	31,496	15,723
HE 13	47,347	33,994	13,353
HE 14	47,263	36,500	10,763
HE 15	47,345	39,513	7,832
HE 16	47,393	40,857	6,536
HE 17	47,652	42,348	5,304
HE 18	52,395	42,646	9,749
HE 19	48,084	41,467	6,617
HE 20	45,710	39,214	6,496
HE 21	45,258	37,182	8,076
HE 22	37,147	34,109	3,038
HE 23	36,146	31,166	4,980
HE 24	36,029	29,274	6,755

Aggregate Showings – September



Aggregate Showings – September

September	Aggregate System Showings	2024 90% YA Requirement + 15.43% PRM	Aggregate Position	Aggregate Deficiencies
HE 1	33,078	25,866	7,211	(758)
HE 2	32,953	24,524	8,429	(606)
HE 3	32,827	23,931	8,896	(534)
HE 4	32,676	24,053	8,623	(542)
HE 5	32,572	25,172	7,400	(685)
HE 6	32,534	27,351	5,183	(911)
HE 7	33,560	28,179	5,381	(543)
HE 8	35,939	28,185	7,754	(395)
HE 9	41,217	28,689	12,528	(327)
HE 10	43,922	29,577	14,345	(385)
HE 11	45,069	30,804	14,265	(471)
HE 12	45,476	32,218	13,258	(562)
HE 13	45,647	34,641	11,006	(776)
HE 14	46,048	37,427	8,621	(998)
HE 15	46,530	40,157	6,373	(1,295)
HE 16	46,615	42,118	4,498	(1,340)
HE 17	46,798	43,566	3,232	(1,450)
HE 18	47,074	44,343	2,731	(1,189)
HE 19	44,214	44,301	(87)	(1,458)
HE 20	43,035	42,885	149	(1,454)
HE 21	41,120	39,612	1,508	(1,316)
HE 22	35,654	35,239	415	(1,323)
HE 23	33,671	31,562	2,109	(1,019)
HE 24	33,546	28,699	4,847	(765)

(estimated)

September	Aggregate System Showings	2025 Load Forecast + 17% PRM	Aggregate Position
HE 1	33,078	27,134	5,944
HE 2	32,953	25,566	7,387
HE 3	32,827	24,576	8,250
HE 4	32,676	24,318	8,358
HE 5	32,572	25,011	7,560
HE 6	32,534	26,656	5,878
HE 7	33,560	27,975	5,585
HE 8	35,939	28,874	7,065
HE 9	41,217	29,456	11,761
HE 10	43,922	30,181	13,741
HE 11	45,069	31,337	13,732
HE 12	45,476	33,147	12,329
HE 13	45,647	35,585	10,062
HE 14	46,048	38,922	7,127
HE 15	46,530	41,914	4,616
HE 16	46,615	43,121	3,494
HE 17	46,798	43,788	3,010
HE 18	47,074	43,683	3,392
HE 19	44,214	42,156	2,058
HE 20	43,035	39,327	3,707
HE 21	41,120	37,389	3,731
HE 22	35,654	34,601	1,053
HE 23	33,671	32,067	1,604
HE 24	33,546	29,875	3,671

Comparing Existing Framework to Slice of Day Framework

Table 15. Number of Load Serving Entities Meeting 2024 Year Ahead Requirements Under the Slice of Day and Current Frameworks.

May		June		July		August		September	
SOD	23	SOD	19	SOD	20	SOD	20	SOD	15
Current	38	Current	38	Current	34	Current	32	Current	27

Table 16. Deficient Load Serving Entities Under Slice of Day by Month and Type.

	May	June	July	August	September
IOU	0	1	1	0	0
CCA	7	12	10	10	15
ESP	8	6	7	8	8

Portfolio Comparisons Between LSEs (May)

Figure 9. Resource Portfolio Breakdown of Load Serving Entities Passing Both Frameworks for May.

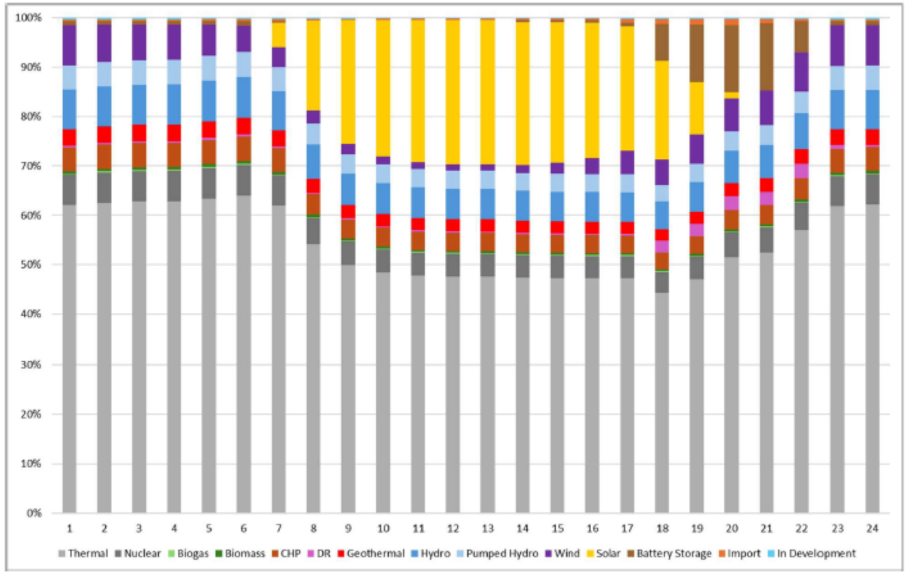
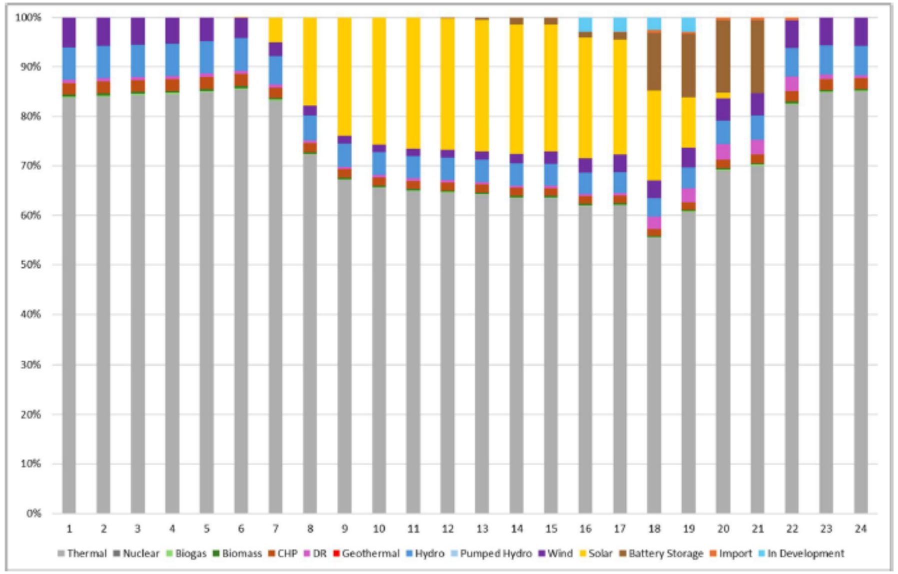


Figure 11. Resource Portfolio Breakdown of Load Serving Entities Only Passing Current Framework for May.



Portfolio Comparisons Between LSEs (September)

Figure 13. Resource Portfolio Breakdown of Load Serving Entities Passing Both Frameworks for September.

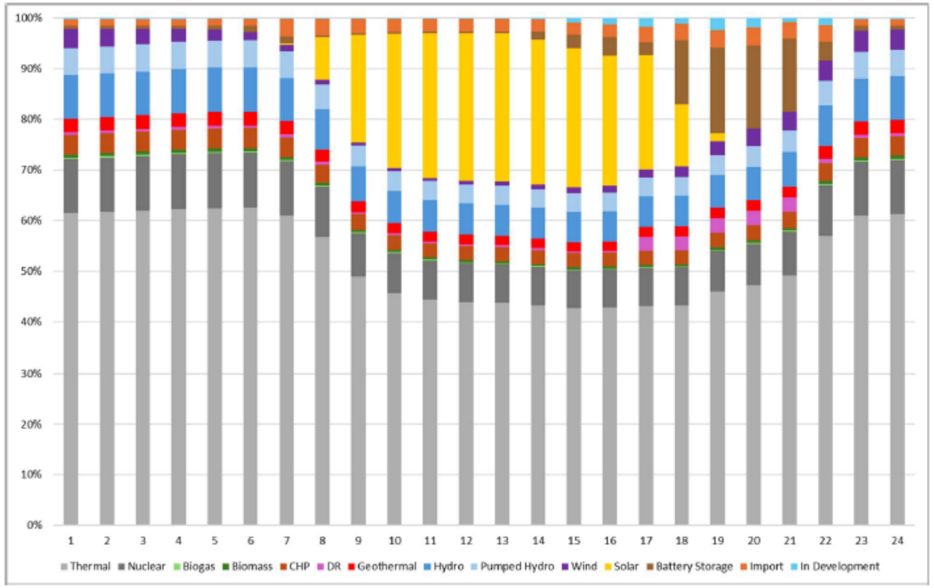
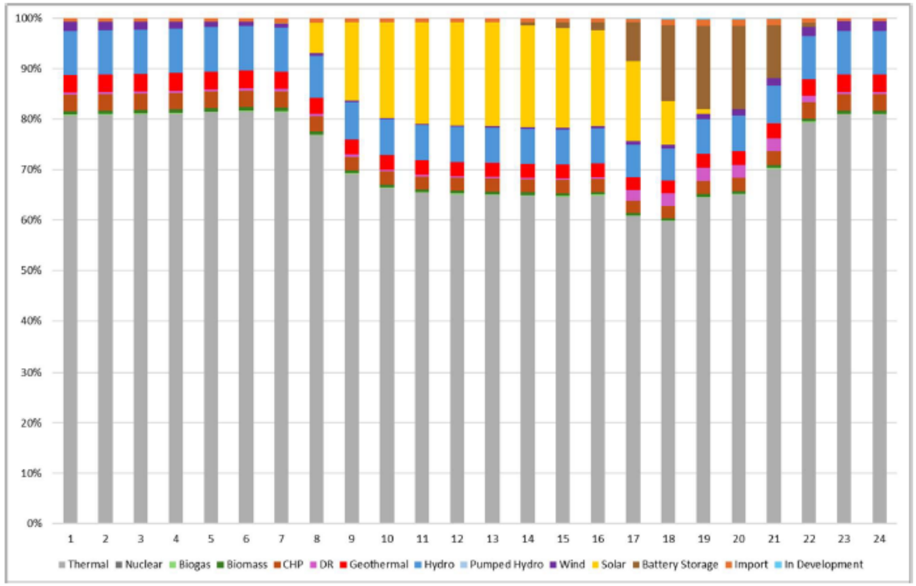


Figure 15. Resource Portfolio Breakdown of Load Serving Entities Only Passing Current Framework for September.



Stack Analysis

Background

- To assess whether enough resources are available on the CAISO grid to meet hourly demand on the forecasted worst days in 2024, ED Staff performed a stack analysis for the months of greatest concern: July, August, and September.

- The CPUC and CEC recently coordinated on a quarterly Joint Agency Reliability Planning Assessment, or Senate Bill (SB) 846 report, which contains a stack analysis with slightly different assumptions from the analysis herein.

Supply Assumptions

- Imports
  - A conservative 4,500 MW estimate and one with 2,300 additional MW. Includes both specified and unspecified.
- November NQC List
- DR uses projected availability for the AAH in months and uses the largest projection for the ELCC stack
- Under Construction (UC)
  - Showing only what was on LSE Year Ahead RA showings. Likely conservative since they showed a subset a resources that are UC, but we have seen many delays.
  - All under development solar resources are assumed to be tracking.
- Batteries were optimized into Pmax for HE 19-21 and half of Pmax for HE 18 and 22, except for some UC.

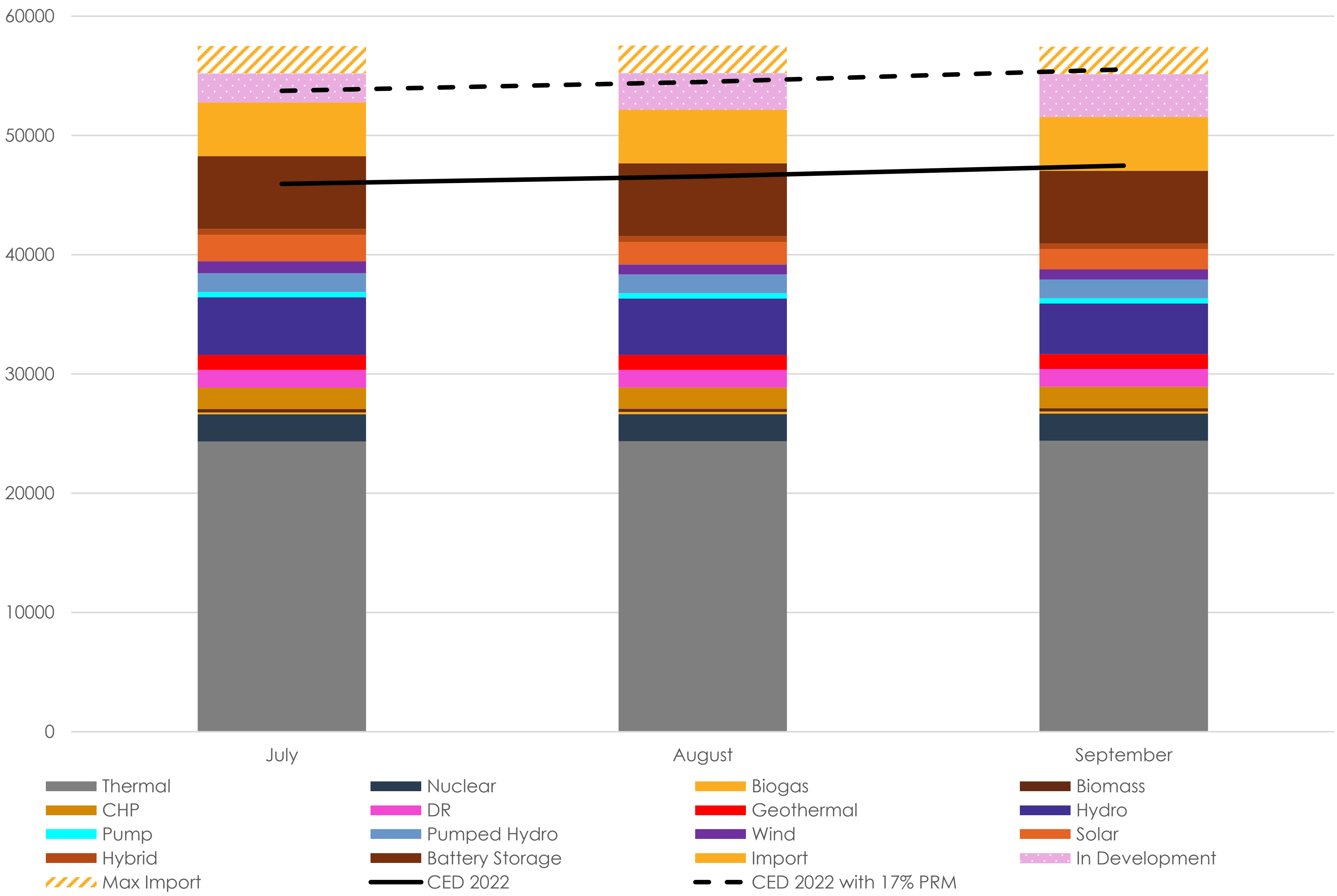
Demand Assumptions

- The 2022 and 2023 California Energy Updates were used to predict energy demand in 2024 and 2025 respectively.
  - Each of the months in question use the worst day hourly load forecast
- A 15.43% PRM was applied to the SOD stack and a 17% PRM was applied to 2025.
- The 2024 demand is the black line and the 2025 demand is the green line. Demand lines with the PRMs are dashed.

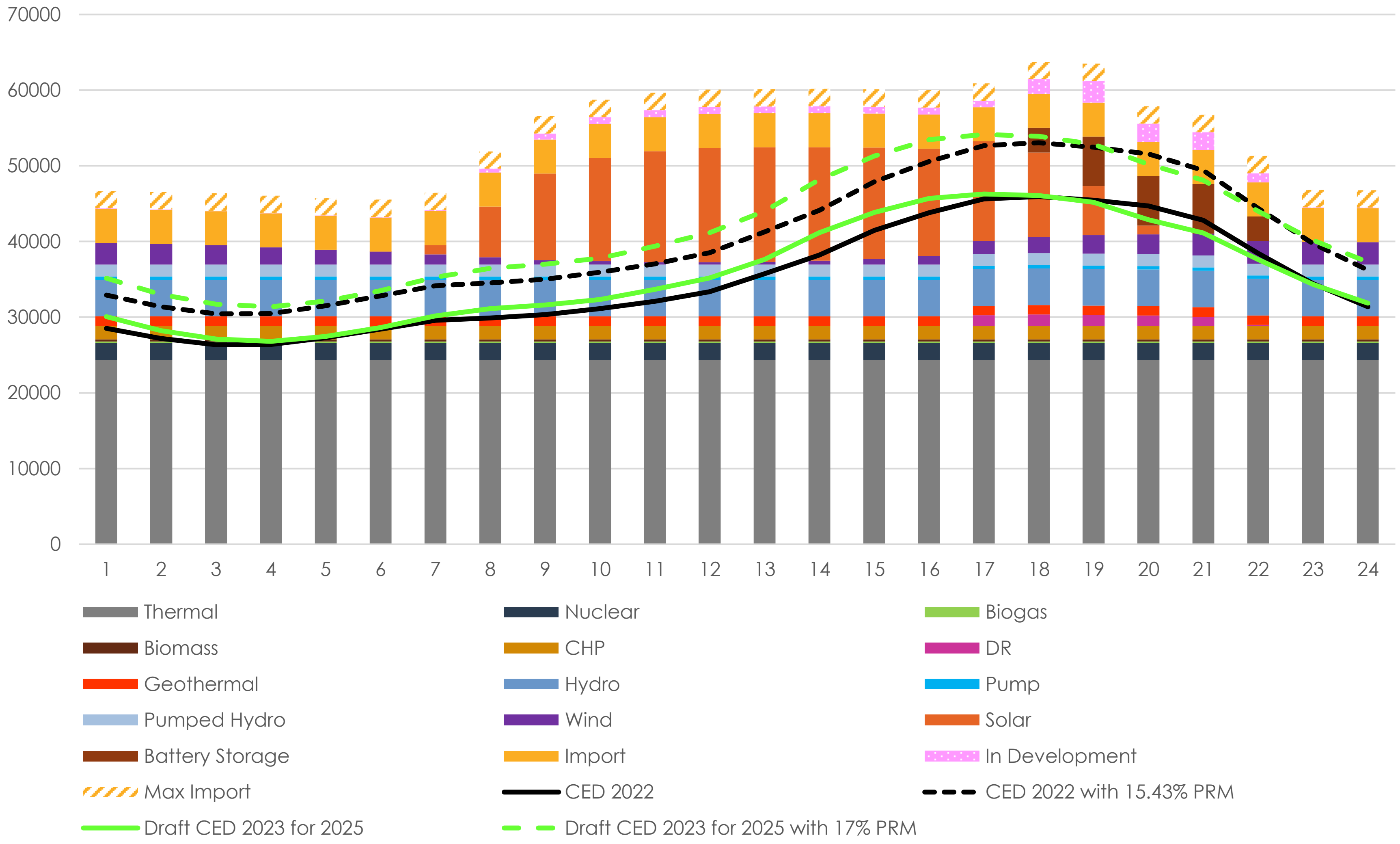
Takeaways

- The following stack analysis graphs show there is sufficient capacity on the system to meet estimated Month Ahead hourly SOD obligations. The month of September shows the tightest supply margins
- Across all three months, the evening peak hours show the tightest supply (HE 19-22).

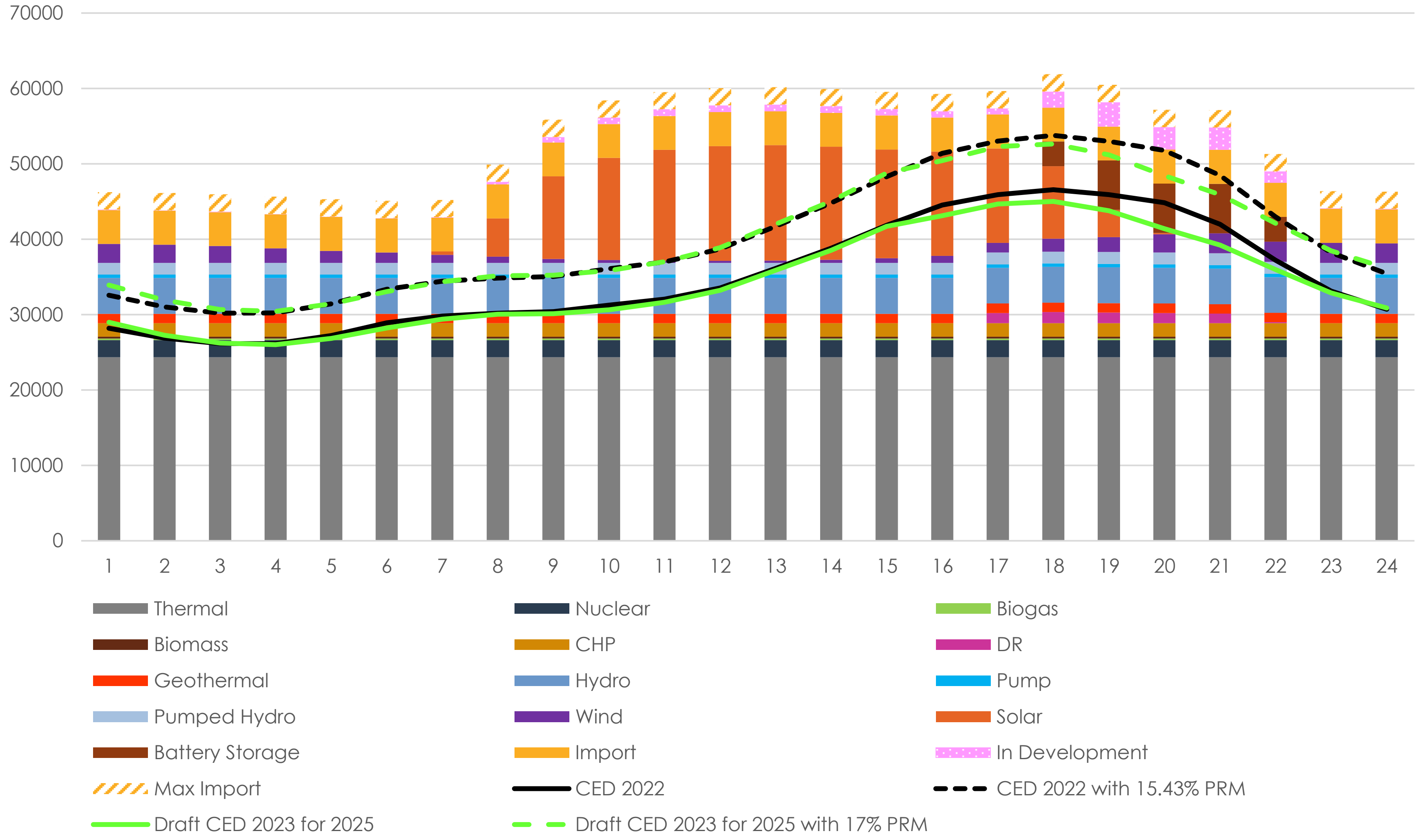
Stack Analysis 2024



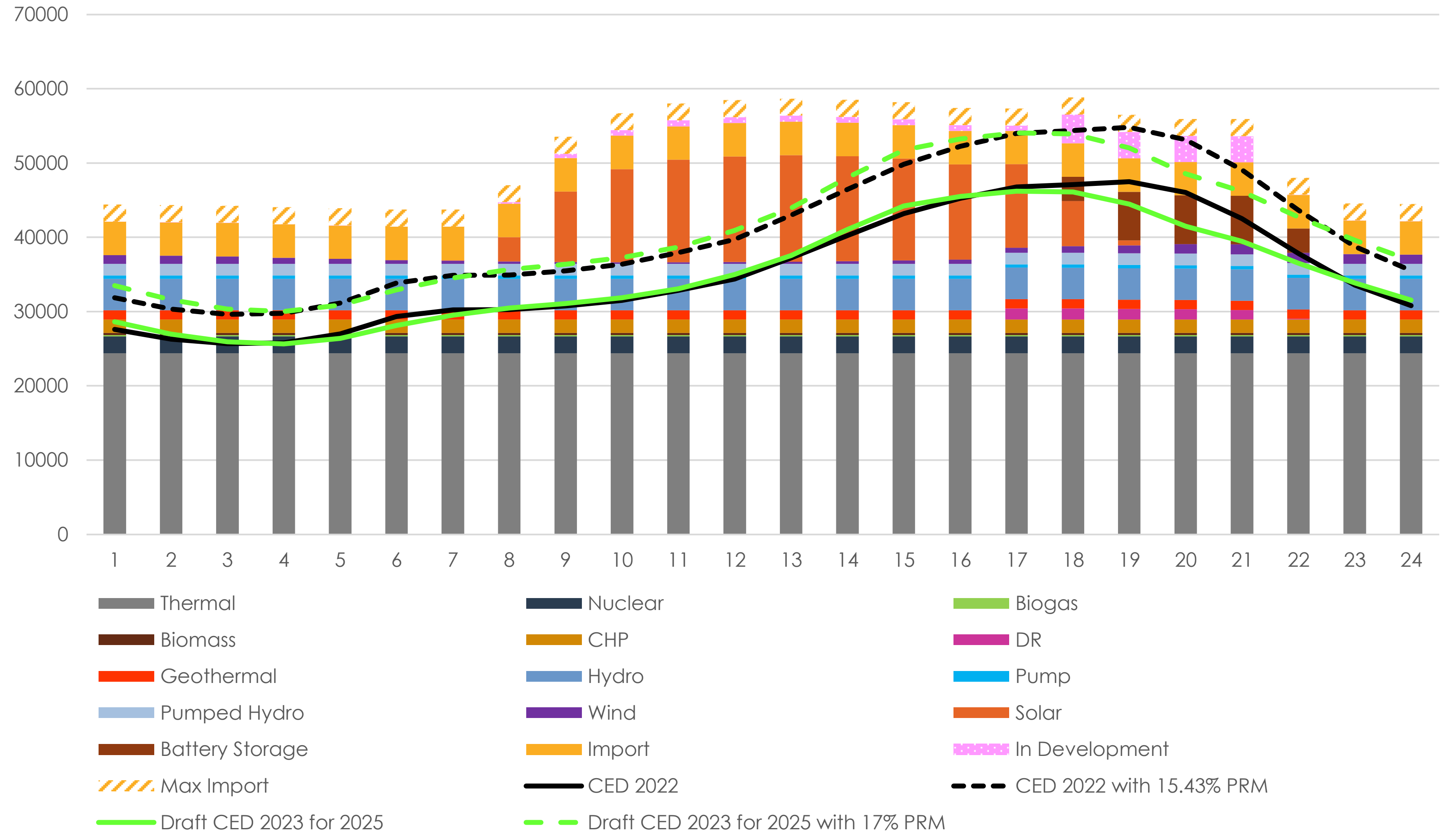
Slice of Day July 2024 Stack



Slice of Day August 2024 Stack



Slice of Day September 2024 Stack



Slice of Day – Next Steps

Slice of Day – Next Steps

- The Test Year 2024 SOD Month Ahead showings for March, June, and September are due to Energy Division on March 1, June 1, and September 1, 2024 respectively.
- Updated LSE Showing Tool will be transmitted to LSEs prior to March 1 filing due date.
- LSEs can currently see their SOD requirements and allocations for 2024 in the "Requirements and Allocations" tab of their LSE Showing Tool templates, however, ED Staff plans to circulate informational-only worksheets providing a further breakdown of these totals, including CPE, CAM, MCAM, and DR allocations for 2024.
  - For the 2025 RA Compliance Year, these worksheets will be provided at the same time LSEs receive their LSE Showing Tool templates with updated allocations.
- Track 1 of R.23-10-011 is dedicated to the most time-sensitive issues in the RA Proceeding, including refinements to the SOD Framework. A Proposed Decision is expected in May 2024 and Final Decision in June 2024.

Form Energy Slice of Day Proposals

February 14, 2024
R.23-10-011

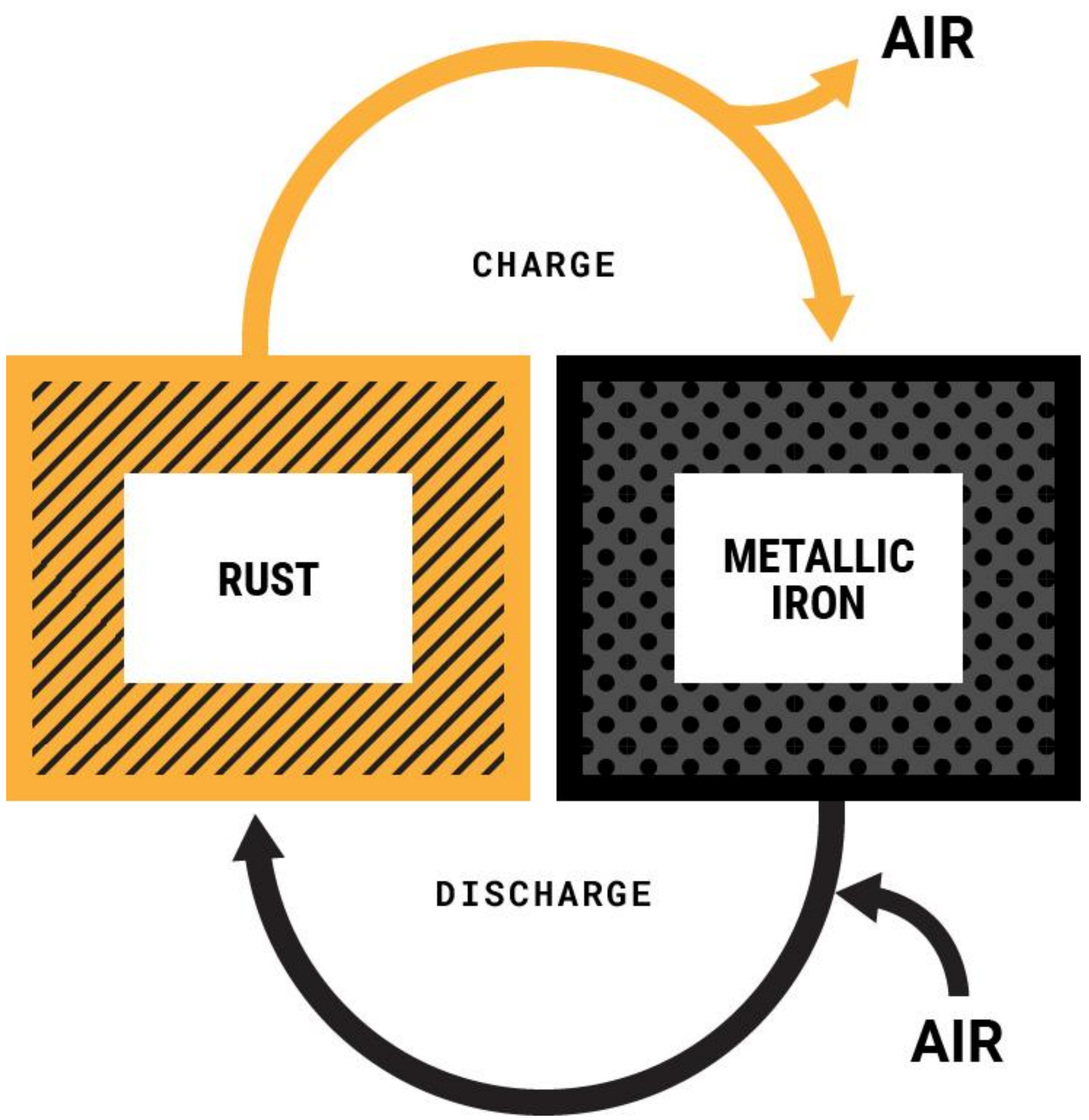
Form energy

Energy Storage
For A Better World

CONFIDENTIAL

Rechargeable iron-air technology for multi-day storage

Form's 100-Hour Reversible Rust Battery



COST
Lowest cost rechargeable battery chemistry.
Chemistry entitlement <$1.00/kWh

SAFETY
No thermal runaway (unlike li-ion)
Non-flammable aqueous electrolyte

SCALE
Iron is the most globally abundant metal
Easily scalable to meet TW demand for storage

DURABILITY
Iron electrode durability proven through decades of life and 1000's of cycles (Fe-Ni)

What makes up a Form Energy system

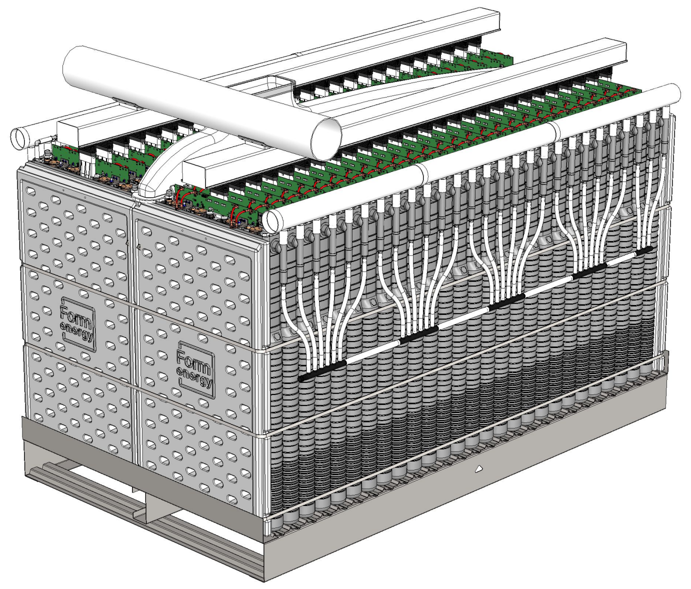
Modular design enables easy scaling to GWh systems

Cell

Electrodes + Electrolyte

Smallest **Electrochemical** Functional Unit

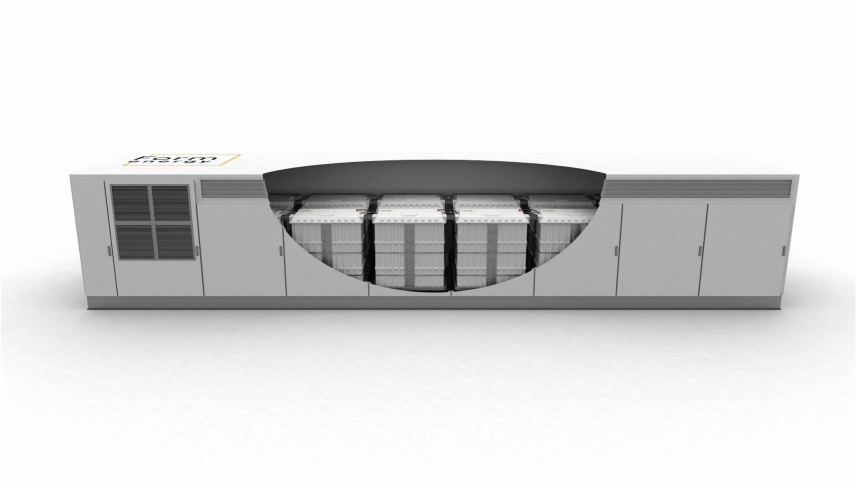
Battery Module



~50 **Cells**

Smallest Building Block of **DC** Power

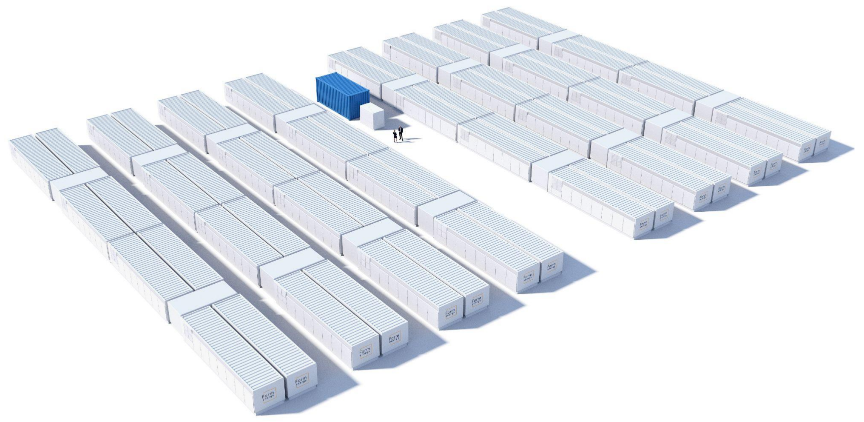
Enclosure



~5 **Modules**

Product Building Block with **integrated module auxiliary systems**

Power Block



~3.5 MW / 350 MWh

<2 acres

~50 - 100 **Enclosures**

Smallest independent system and **AC Power** building block

System

10 MW / 1000 MWh

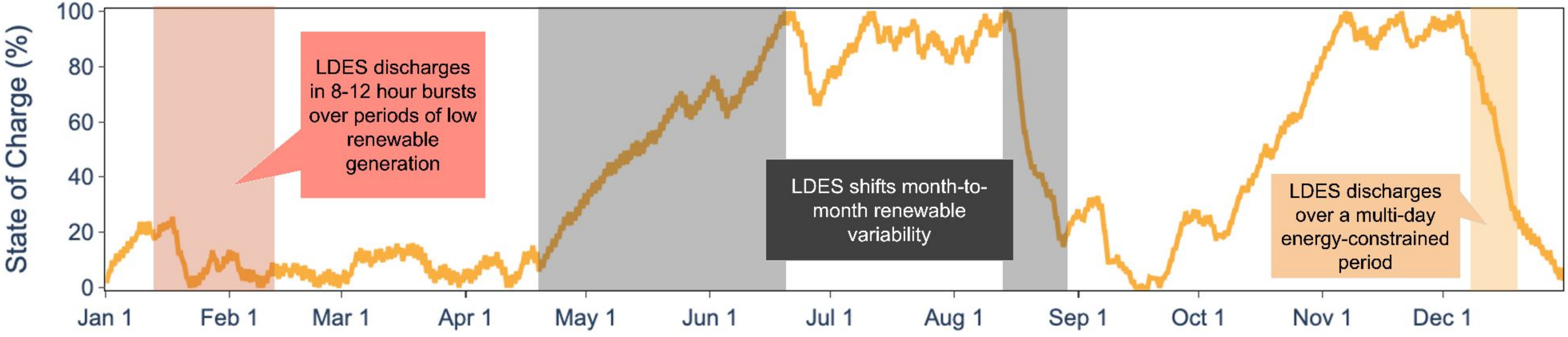
5+ acres

10s - 100s of **Power Blocks**

Commercial Intent System

Multi-Day Storage operates year-round to balance seasonal, multi-day, and intra-day variability

State of charge of 100-hour energy storage in CAISO 2045, No In-state Combustion



Intra-Day

Seasonal Up
(net charge with excess renewables)

Seasonal Down
(net discharge during peak load season)

Multi-Day

Commercial Engagements

First-of-its-kind **1.5 MW /150 MWh** MDS project in Cambridge, Minnesota to come online in 2024

Two 10 MW / 1,000 MWh MDS systems; one in Becker, MN and one in Pueblo, CO. Both expected to come online as early as 2025

5 MW / 500 MWh MDS system in collaboration with the California Energy Commission in Mendocino County; online by 2025

10 MW / 1000 MWh MDS system in New York to come online as early as 2025

15 MW / 1500 MWh MDS system in Georgia to come online as early as 2026

5 MW / 500 MWh MDS system in Virginia to come online as early as 2026

Form Factory 1: Commercial-Scale Manufacturing

Transforming Weirton Steel Land for Battery Manufacturing in West Virginia

- **Total Local Investment:** $760 million
- **Construction Start:** Early 2023
- **Production Start:** Late 2024
- **Jobs:** Minimum of 750 full-time jobs

Location Benefits

- Close to our existing pilot manufacturing facility in PA
- Strong natural infrastructure
- Local manufacturing know-how

Factory Function

- Semi-to-fully automated cell, module, & enclosure assembly
- Ability to scale production in modular blocks

Study Overview

Evaluated the role of Multi-Day Storage (MDS) and Long-Duration Storage (LDES) in California at bulk-system level and local capacity level
https://www.energy.ca.gov/publications/2024/assessing-value-long-duration-energy-storage-california

Meeting SB 100 & electric sector decarbonization goals

CAISO System

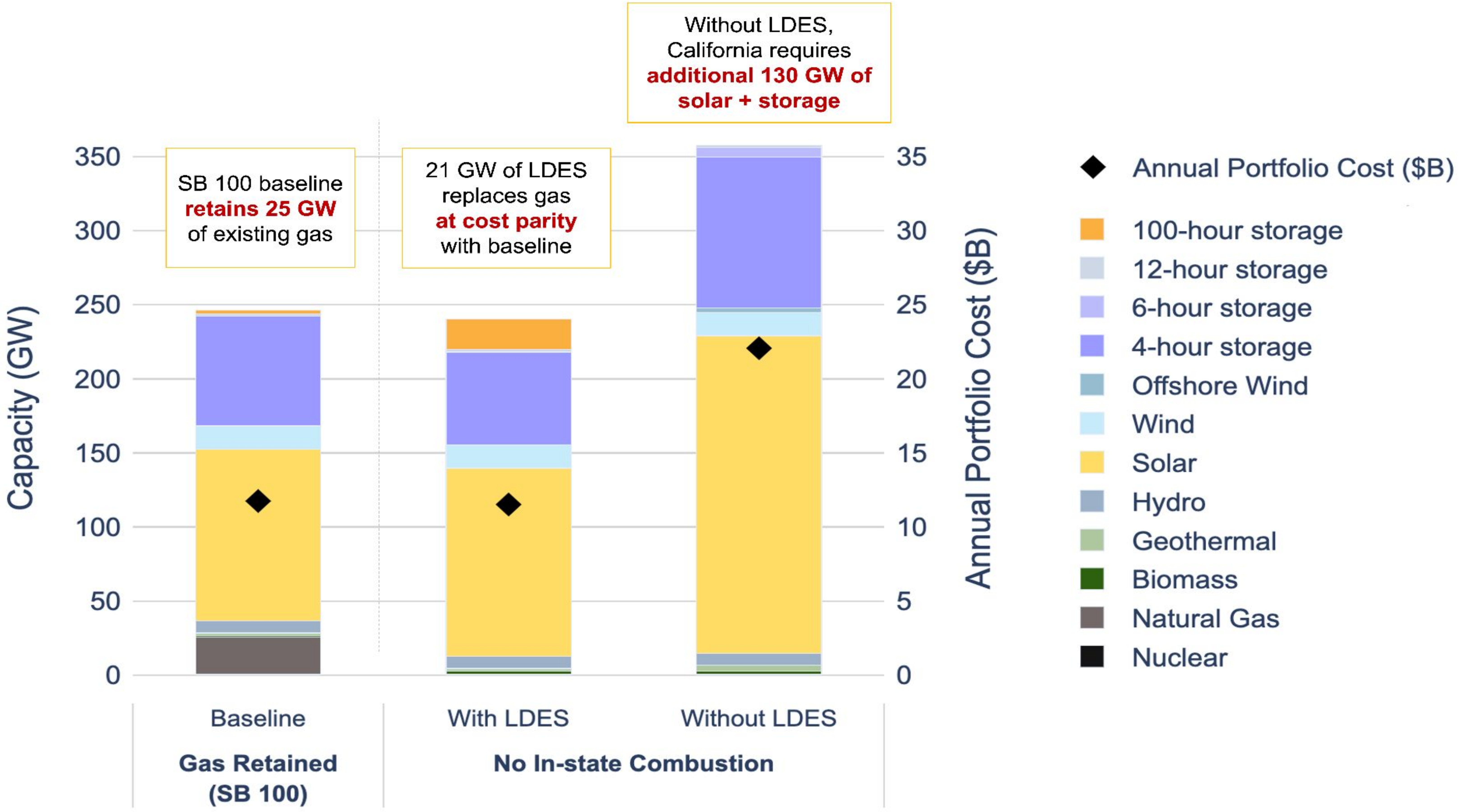
Local capacity and criteria air pollutant reduction benefits

LA Basin Local Capacity

Multi-Day Storage Enables CA to Fully Retire the Gas Fleet at cost parity with SB 100 portfolios that retain all existing gas capacity

- With MDS: California avoids the operational costs required to keep gas generation online
- Without MDS: Portfolio costs increase significantly due to needs to overbuild solar and short-duration storage to maintain reliability

Least Cost 2045 CAISO System Portfolio and Costs



Key Results

- Multi-Day Storage can cost-effectively replace existing gas generation capacity in CAISO
- Multi-Day Storage avoids overbuilding >100 GW of resources otherwise needed to accommodate multi-year weather variability
- Multi-Day Storage plays a critical role in maintaining system operations during periods of grid stress and protecting against short and long-term weather uncertainty
- Multi-Day Storage maintains local reliability in the Los Angeles basin while allowing reliable operations even if gas-fired generation were retired in disadvantaged communities

Form Energy’s Requests in R.23-10-011

- Establish framework for accrediting Multi-Day Storage Systems
  - *Keep it simple, but appropriate*
    - Multi-Day Storage cannot fully dispatch within 24 hours; cannot be recharged within 24 hours
    - Not logical or required to show recharge within same 24-hours; dispatch runs across many days
  - *Look to treatment of other resources that have similar characteristics (pumped hydro)*
    - Recognize that deeper analytics could be done on these resource; look forward to engaging
    - Do not require a charging/discharge cycle within 24-hours in SOD
    - Interim methodology, given importance of implementing SOD and the breadth of issues in proceeding

Form Energy's Requests in R.23-10-011 (cont'd)

- Ensure Resource Adequacy construct gives consideration to multi-day events (this docket, or IRP, or other docket)

- Expression of support to consider changes to local capacity requirements under RA program to allow showing as firm resources that can meet local capacity requirements

CESA Party Proposals (R.23-10-011)

February 14, 2024

CPUC Party Proposal Workshop

CALIFORNIA ENERGY STORAGE ALLIANCE

Proposal 1

Allow resources scheduled to achieve COD by the start of the Compliance Month to count on LSE RA Plans

- The Commission should not penalize LSEs relying on contracted resources achieving COD prior to the compliance month
- Interactions with CAISO backstop process not critical to a Commission rule change and can be worked out in a CAISO stakeholder process

Current rules were established 15 years ago

- Currently, resources must achieve COD prior to the Month Ahead RA Plan submittal deadline (T-45).
- The lag between achieving COD and being eligible to be on an LSE RA Plan has unnecessary economic and reliability impacts
- Current rule was an improvement 15 years ago, but CPUC and CAISO were concerned that there may be delays in testing or other steps to achieving COD.
- At the time of the current rule, deadlines were T-30 and CAISO would make backstop decisions after T-10, with less sophisticated systems/processes

There is substantial value to be gained

- For Compliance Month August 2023, an additional ~359 MW of RA capacity achieved COD between T-45 and T-1
  - *Commission penalties were not needed, CAISO backstop was not needed*

Compliance Month	Capacity Achieving COD Between T-45 and T-1 (MW)	Potential RA Value (MW)
January 2023	581	272
February 2023	1,060	551
March 2023	570	350
April 2023	174	131
May 2023	2	0
June 2023	573	412
July 2023	585	511
August 2023	638	359
September 2023	747	392
October 2023	738	419
November 2023	599	196
December 2023	1,368	548

Interactions with CAISO's processes can be worked out in a CAISO stakeholder process

- There are interactions with CAISO's backstop procurement process. CAISO will need to make a backstop procurement decision prior to the Compliance Month.
  - *However, final cost allocations can occur later*
- CAISO's systems/processes are now much more sophisticated than they were 15 years ago
  - *CIRA system allows on-demand calculation of RA positions*
  - *CIRA system collects CPM offers and optimizes selections subject to designation criteria*
- CAISO has recently demonstrated that its processes can support backstop decisions much closer to the start of the compliance month
  - *In July 2023, CAISO made a call for additional backstop capacity at T-20 and asked for responses by T-11*
  - *CAISO then successfully procured two additional resources*
  - *One of the resources CAISO procured achieved COD on T-5*

Proposal 2

Permit LSEs more flexibility in meeting charging sufficiency requirements

- Enhance SOD framework by instituting an initial system-wide storage charging sufficiency test prior to requiring sufficiency at an LSE level
- System-wide test should use only deliverable resources

Energy sufficiency requirements are overly burdensome due to the SOD framework creating an artificial barrier to efficient procurement

- Energy sufficiency requirements are overly burdensome due to the SOD framework creating an artificial barrier to efficient procurement
  - *LSEs cannot transact charging sufficiency on an hourly basis*
  - *Some parties describe additional implementation issues with appropriately assessing charging sufficiency on individual plans*
- If framework is left unchanged, it would further exacerbate the current supply scarcity situation and RA affordability issues
  - *RA is currently in tight supply, causing higher capacity prices*
- SOD framework introduces constraints that go above and beyond what is needed by the CAISO to produce a reliable dispatch

Table 15. Number of Load Serving Entities Meeting 2024 Year Ahead Requirements Under the Slice of Day and Current Frameworks.

May		June		July		August		September	
SOD	23	SOD	19	SOD	20	SOD	20	SOD	15
Current	38	Current	38	Current	34	Current	32	Current	27

Table 16. Deficient Load Serving Entities Under Slice of Day by Month and Type.

	May	June	July	August	September
IOU	0	1	1	0	0
CCA	7	12	10	10	15
ESP	8	6	7	8	8

Enhance SOD framework by instituting an initial system-wide storage charging sufficiency test prior to requiring sufficiency at an LSE level

- Energy Division staff would use the aggregate RA plan data, MRD resource constraints, and determine if the deliverable resources are capable of meeting storage charging sufficiency requirements
- If the result of this initial test shows the fleet is deficient, assess individual LSEs non-compliance penalties
- Each LSE should receive diversity benefits from initial system-wide energy sufficiency test
  - *The CPUC would only penalize for the quantity that the system is short*

Proposal 3

Update the QC counting methodology for hybrid and co-located resources to reflect the SOD charging sufficiency test

- The SOD framework accounts for grid-charging restrictions better than the current QC methodology
- Recent Commission Decisions have not clarified QC counting for hybrid and co-located resources with grid-charging restrictions under the SOD framework

Hybrid and co-located resources with grid-charging restrictions are unduly under-qualified within the SOD framework

- Currently, the QC of the renewable component of hybrid and co-located resources with grid-charging restrictions are reduced to account for the energy served to the energy storage component
- Grid-charging restrictions do not restrict the renewable component's ability to provide energy to both the on-site energy storage resource or grid storage resources

SOD performs all necessary energy sufficiency verifications for hybrids and co-located resources, making the current special-case QC methodology obsolete

- Propose to eliminate the reduction to the QC of the renewable component of a grid-charging restricted hybrid and co-located resources
  - The renewable component’s QC be calculated the same as any other renewable resource QC,
  - the energy storage component be calculated the same as any other energy storage QC, and
  - the total QC value of the resource be the sum of the two components limited by the Point-of-Interconnection (“POI”) limit.

Proposal 4

Institute an explicit CPE soft-offer cap in lieu of fines or penalties

- CPE framework does not define “unreasonably high” prices causing CPE to be overly conservative
- CPE is not subject to non-compliance penalties for failure to procure local RA as individual LSEs would, so the opportunity cost of non-compliance undermines the Commission’s objective to not be overly reliant on CAISO backstop

CPE is leaning on CAISO's backstop procurement more than the Commission intended

- CPE procurement has been very deficient
- The Commission stated "[w]e do not intend to allow the CPE to rely on CAISO backstop mechanisms to supplant the central procurement process; instead, we seek to minimize backstop procurement while also mitigating market power"
- CPUC non-compliance penalties cost $8.88/kW-month and CPM costs $7.34/kW-month
  - *Entities in SDGE-IV local area are still subject to this combined non-compliance cost*

Achieve market power mitigation goals and give clarity on "unreasonably high" prices

- The Commission can achieve its market power mitigation goals by instituting a formulaic soft-offer price cap that equals the sum of the CAISO CPM soft cap and the higher of the system and local RA penalties for LSEs in summer months.
    - Today: $7.34/kW-month + $8.88/kW-month = $16.22/kW-month
- The CPE should be given discretion to award offers above this price cap if it can demonstrate the offer does not violate market power mitigation to the independent evaluator and a procurement review group.
    - This would formalize a review process to determine if procurement at higher prices is in the best interest of ratepayers before deferring to CAISO CPM

PG&E Track 1 Proposals

(Import Allocation Rights)

February 14, 2024

Presenter: Luke Nickerman

Clarifications on Import Allocation Rights for Resource-Specific Solar and Wind Resources

- Imports must be paired with an import allocation right (IAR) to count for RA (D.05-10-042)
- Slice-of-day changes the existing single monthly value to 24 values for the month
- This presents the question of which value will be used for the IAR
- In D.23-04-010, the Commission stated that it would provide CAISO with "the greater of the peak hour value and a very small non-zero value (e.g., 0.01 MW) if the minimum value is zero. Meaning CAISO will use a single NQC value (HE 19 for the example at right)
- The CAISO indicated in office hours that they intend to use the peak hour value, which is HE19 in the example at right
- PG&E understands that this likely needs to be codified in a CPUC decision as well

Hour Ending	Net Qualifying Capacity[9]
6	0.07
7	2.81
8	8.58
9	13.02
10	15.55
11	17.22
12	18.00
13	18.14
14	18.11
15	17.49
16	16.19
17	14.20
18	10.85
19	**5.18**
20	0.65

Loss of Load analysis – Proposed Stress Tests of Monthly SOD framework;
Stress tests of Path 26 constraints.

Combined Proposals 1 and 4

Mounir Fellahi & Behdad Kiani
Energy Resource Modeling Team, Energy Division
February 14th, 2024

Background – PRM Adoption and Regulatory Decisions

- CPUC has shifted the RA program from a single monthly capacity requirement to capacity requirements for the 24 Slice-of-Day (SOD) approach.
- The SOD framework ensures reliability by requiring LSEs to show sufficient capacity under contract to serve electricity demand at all hours of the “worst day” in each month. It also seeks to simplify resource counting and address the issue of over-procurement.
- The year 2024 will serve as a test period for transitioning from a monthly RA requirement to a 24-hour slice-of-day requirement, with full implementation planned for 2025.
- In Decision (D.)22-06-050, the 17% Planning Reserve Margin (PRM) was adopted for 2024, with the goal of transitioning to full implementation in 2025.

Background – PRM Adoption and Regulatory Decisions

- Decision D.23-06-029 reaffirms the 17% Planning Reserve Margin (PRM), based on a refreshed Resource Adequacy (RA) Loss of Load Expectation (LOLE) study submitted to the RA proceeding in January 2023.
- Authorization in D.23-04-010 for the integration of PRM calibration tools, as proposed by the Natural Resources Defense Council (NRDC) and Southern California Edison (SCE), to translate the results of the LOLE study into the 24-hour Slice-of-Day (SOD) framework.
- Publication, revision and quality control of the initial SOD PRM calibration tool resulted in a calculated PRM of 15.43% for September. A single PRM applied to all hours of the month and year.
- The Commission noted that it would consider multiple PRMs that may differ by month as appropriate to the SOD framework in future phases of the proceeding.

PRM Options for 2025 RA Compliance Year Before Revised LOLE study Published

Option 1: Implement 2024 Portfolio Translation of 15.43%

•Utilizes the 2024 RA LOLE portfolio to translate into a 15.43% effective PRM for September, based on current exceedance profiles and the CEC forecast.

Option 2: Maintain 17% PRM Status Quo

•Retains the 17% PRM for 2025 to set LSE RA program obligations, aiming for a more balanced LOLE across the summer months.

•Adopts a SOD PRM slightly higher than the 15.43% required in September, and potentially lower in other months (refer to Table 2 from the proposal).

•Recognizes that the September SOD PRM calibration result (15.43%) closely aligns with the CEC's monthly managed September PRM (14.5% - refer to Table 1, row 7 from the proposal) that informed the 17% PRM established for 2024 and 2025 in D.23-06-029.

Background – Stress Test on Path 26 Zonal Requirements

1. In D.07-06-029, the Commission addressed zonal transmission constraints by adopting a Path 26 counting constraint
2. Later, in D.19.06-026, the Commission adopted Energy Division and SCE’s proposal to eliminate the Path 26 constraint.
3. The most recent RA LOLE study (the 2024 RA LOLE Study), observed that LOLE results were higher in the SCE TAC area than PG&E TAC area when the model was limited to the established Path-26 rating.
4. Wheel throughs from the Northwest to the Southwest could impact this zonal constraint which could have further impacts on reliability metrics and procurement planning (RA and new resource development).
5. For this purpose, it is important to evaluate the effect of high priority wheel throughs on overall reliability as well as the effect on RA and IRP procurement as well as test the reliability impact of the Path 26 path ratings under normal operations.

Summary and Timeline of Proposal Activities

Following the December 18, 2023, Scoping Memo and Ruling in R.23-10-011:

- New LOLE study to be conducted in Q2 2024 to inform the 2026 RA PRM.
- Conduct stress tests to investigate monthly SOD results, ensuring LOLE meets acceptable metrics.
- Use completed SOD translation tool for translating LOLE study results into a monthly PRM for the 2026 RA compliance year.
- Results of the 2026 study will be released; parties will be given an opportunity to comment in Track 2 of the current RA proceeding.
- Energy Division to prepare a draft report on Inputs and Assumptions by March 15, 2024, as part of Track 2.
- Deadline for comments on Inputs and Assumptions set for April 1, 2024.
- Deadline for party proposals set for May 24, 2024.
- Stress test results for both SOD and Path 26 will to be published with the revised LOLE study by June 3, 2024.
- Workshop on proposals and LOLE study scheduled for June 28, 2024.
- Opening comments deadline set for July 29; reply comments due by August 19, 2024.

Stress Tests Flow Chart Including Path 26 Sensitivity

Annual LOLE Study Baseline

If LOLE>0.1, add Perfect Capacity until LOLE is <=1

If LOLE <= 1, proceed

Apply SOD tool to the Peak Month to obtain the Peak Month PRM

Apply the Peak Month PRM across all Months

If LOLE is =<0.1, the Peak PRM will be adopted; if not assess the unserved energy magnitude, then proceed:

Use 3 PRMs (or more): one PRM for the peak month, one for the other peak months, and one for off-peak months, while ensuring LOLE<= 0.1

Use two PRMs: one PRM for peak months and one for off-peak months, while ensuring LOLE<= 0.1

Apply Stress Test on Path 26 Zonal Requirements

Propose adjustments to import constraints and Path 26 assumptions to enhance system reliability

Apply SOD tool to the Peak Month to obtain the Peak Month PRM

Apply the Peak Month PRM across all Months

PRM Calculation Using SOD Calibration Tool

- SOD tool utilizes Net Qualifying Capacity (NQC)-based portfolio for PRM calculations, qualifies wind/solar resources by hourly exceedance profiles drawn from actual generation, and measures resources against managed hourly electricity demand for the target month.
- Input Process:
  - Inputs 1-in-2 managed “worst day” hourly load values for the month derived from the IEPR Hourly Load Model (HLM).
  - Qualifies resources by NQC rules or hourly exceedance profiles as appropriate
- PRM Setting Optimization:
  - Uses the Solver function in the PRM Setting tab to first identify the minimum PRM across 24 hours without storage, then optimizes storage integration to maximize the minimum PRM while ensuring allocations do not exceed storage capacity and energy availability.

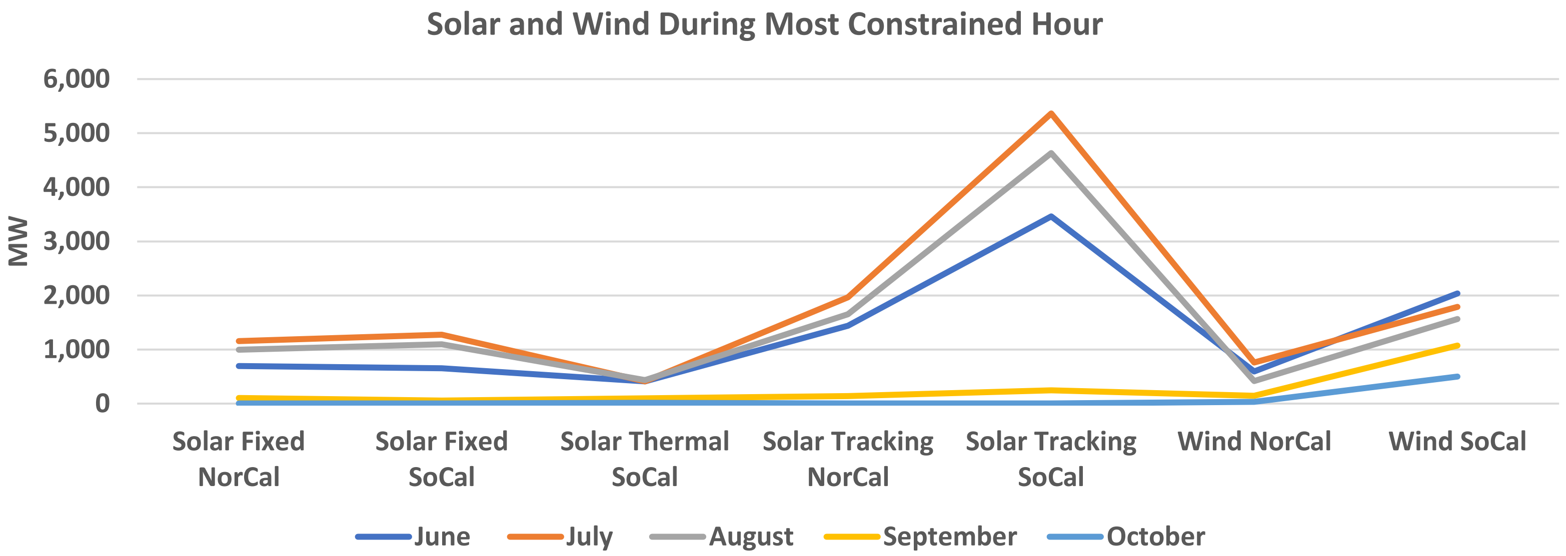
Monthly SOD PRM Results and Analysis

- The table displays SOD-calibrated PRM values for June, July, August, September, and October and the most constrained hours.
- The most constrained hours shift due to changes in consumption patterns and solar insolation levels throughout the year.
- Higher summer demand and lower renewable energy production in September compared to August result in the minimum PRM in September.
- Months like October and June have higher PRMs due to lower electric demand.

Months	PRM	Managed Peak (MW)	Most Constrained Hour, Hour Ending (HE)
June	34.96%	42,707	19
July	29.27%	45,908	18
August	25.81%	46,500	18
September	15.43%	47,325	19
October	34.37%	38,861	19

Reasons for Monthly PRM Differences

- Higher summer electric demand and lower renewable energy production in certain months lead to lower PRMs.
- Hydroelectric power availability, which varies by month influences the PRM.
- Seasonal variations in weather impact both demand and renewable energy production, particularly for solar and wind.



Stress Tests

- Stress tests are designed to evaluate the resilience of the grid under various challenging scenarios.
- Purpose: To ensure the reliability of the grid across all months, especially during peak demand periods.
- Also designed to test a static PRM across offpeak months to ensure stable reliability across the year
- Stress tests help identify potential weaknesses in the system and guide adjustments to PRM and resource allocations.

SOD Stress Test Methodology

1. Staff will design and conduct an updated LOLE study based on a revised set of Inputs and Assumptions.
2. In the event of LOLE that exceeds 0.1 total across the year, add perfect capacity to the peak month only until LOLE is 0.1 or less.
3. Analyze the resulting Loss of Load Expectation (LOLE) and magnitude of unserved energy by month.
4. Apply the same SOD PRM (peak month PRM) across all months (15.43% SOD PRM) by reducing the PRM in other months by adding flat blocks of load.
5. If LOLE is ≤0.1, we are done, and this will lead to one single PRM.
6. If LOLE > 0.1:
   a. Add perfect capacity to constrained months to lower LOLE to 0.1. This will result in higher peak month PRM (PRM > 15.43%). This approach will also lead to one single PRM, but it requires resources on the top of what in the portfolio for the peak month.
   b. Two distinct (or more) PRMs—one for the peak month and another for the rest of the year. This can be done by adjusting the PRMs in less constrained months until the LOLE is ≤0.1.

Proposal- Stress Test on Path 26 Zonal Requirements

- Staff will conduct LOLE modelling during Track 2 of the current RA proceeding and will assess Path 26 path rating.
- The study steps are summarized as follows:

  a. Develop sensitivities to assess the impact of varying Path 26 assumptions on LOLE.
  b. Evaluate the future capacity versus peak demand in each IOU service area, with a focus on the zonal requirements.
  c. Investigate potential retirements and developments that may affect capacity balance between zones.
  d. Propose adjustments to import constraints and Path 26 assumptions to enhance system reliability.

- Staff also plans to conduct an analysis of RA filings during the constrained months of 2021-2023 to determine whether LSEs have collectively exceeded Path 26 constraints.

Expected Outcomes - Stress Test on Path 26 Zonal Requirements

This study aims to contribute insights to California's energy planning efforts in order to ensure a resilient and balanced energy infrastructure for 2026 and 2027. Specifically:

1. **Improved LOLE Modelling:** Enhance the accuracy of LOLE modelling by considering refined import constraints and Path 26 assumptions.
2. **Strategic Capacity Development:** Provide recommendations for targeted capacity development, specifically addressing the imbalance in the SCE area.
3. **Enhanced Path 26 Optimization:** Propose adjustments to import constraints and Path 26 assumptions for improved system reliability.
4. **Consider Reinstitution of Zonal Constraints:** Propose zonal RA requirements that address wheel through pressures on Path 26.

Timeline for Proposals 1 and 4

Track 2 Schedule	
Energy Division Staff to publish Inputs and Assumptions to be used in RA LOLE study	March 15, 2024
Parties Submit Comments on Inputs and Assumptions to be used in RA LOLE study	April 1, 2024
Energy Division Staff to publish LOLE study	June 3, 2024
Workshop on proposals and LOLE Study	June 28, 2024
Opening comments on all proposals filed	July 29, 2024
Reply comments on all proposals filed	August 19, 2024

Monthly Planning Reserve Margin Proposal

February 15, 2024 CPUC Resource Adequacy Workshop

NP ENERGY

Overview: Resolving Final PRM Details

- Alignment of the Planning Reserve Margin (PRM) with a 0.1 LOLE standard is a key workstream of the CPUC Resource Adequacy (RA) Reform initiative

- General methods were developed, tested, and adopted in Slice of Day Working Group, but final details remain unresolved, with specific need to address variation in reliability need across months
  - Prior CPUC decisions adopted a single annual PRM – but various analyses have illustrated that a single annual PRM will not align monthly requirements to the LOLE study
  - Proposals from ACP, CAISO, WPTF, and Energy Division are intended to stress test and refine the final PRM steps with a combination of SERVM- and Excel-based stress testing

- Intent of this presentation is to facilitate stakeholder discussion on options to resolve final PRM calibration details and resolve path forward for 2025 and beyond

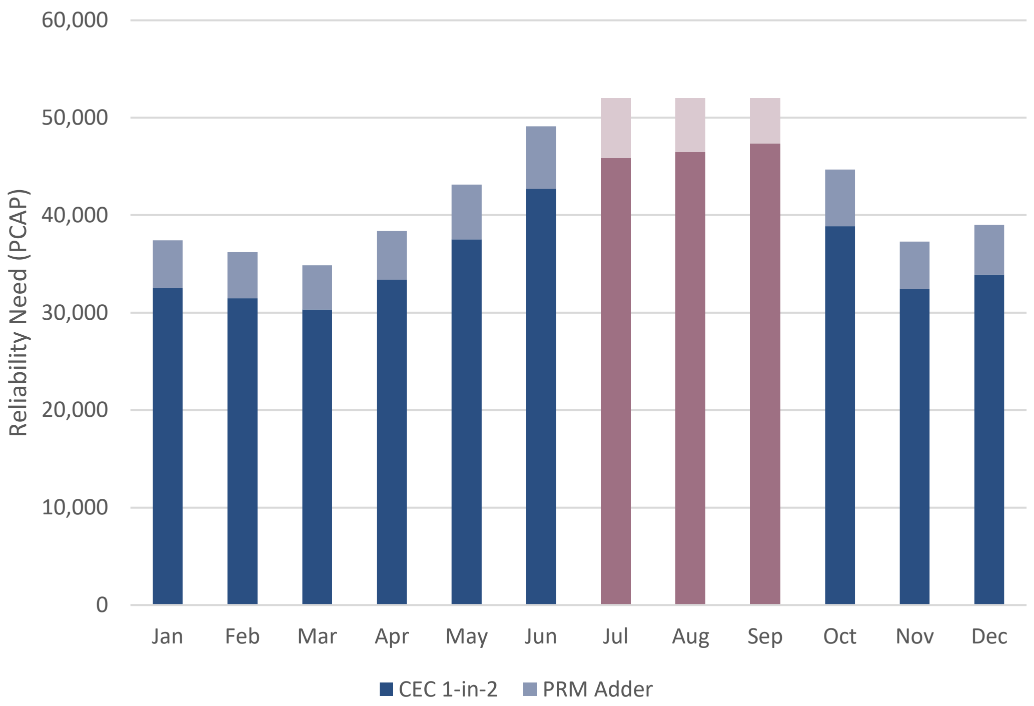
Importance of PRM: Why We're Here

- The Planning Reserve Margin (PRM) is a critical RA program parameter
- The PRM is intended to link reliability modeling results (SERVM) with RA program compliance requirements
- A correct PRM is critical for ensuring RA program requirements:
  - Are sufficient to meet reliability policy goals
  - Are not excessive to reliability requirements or available resources
- A robust PRM implementation is one of four key refinements necessary to align the RA program with principles of probabilistic reliability modeling

<u>Aligning RA Program with Probabilistic Modeling</u>

- ❑ LOLE-Based PRM Process
- ❑ ELCC-Aligned Resource Profiles
- ❑ Outages into Counting Rules
- ❑ Event-Day Load Shapes (>1-in-2)

ACP-CA Monthly PRM Proposal



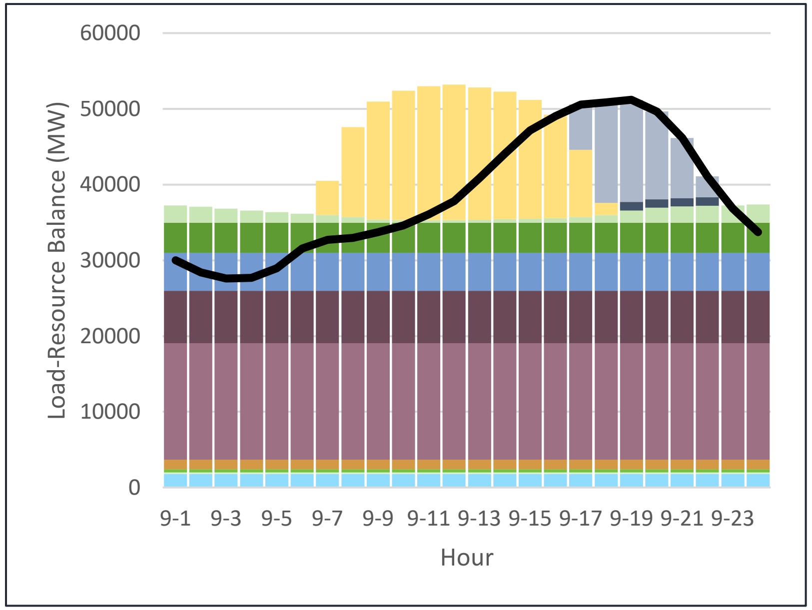
Illustrative Representation of Monthly PRM Proposal

As a straw proposal, ACP-CA reintroduced NRDC's Monthly PRM proposal summarized in the WG Report (p. 114):

- Peak Months: Any month with LOLE receives specified PRM to require full annual portfolio
  - July, August, September
- Off-Peak Months: Generic PRM applied to off-peak months
  - October-June
- Stress testing in SERVM to identify and resolve any reliability events introduced by generic off-peak PRM values

Slice of Day PRM Background

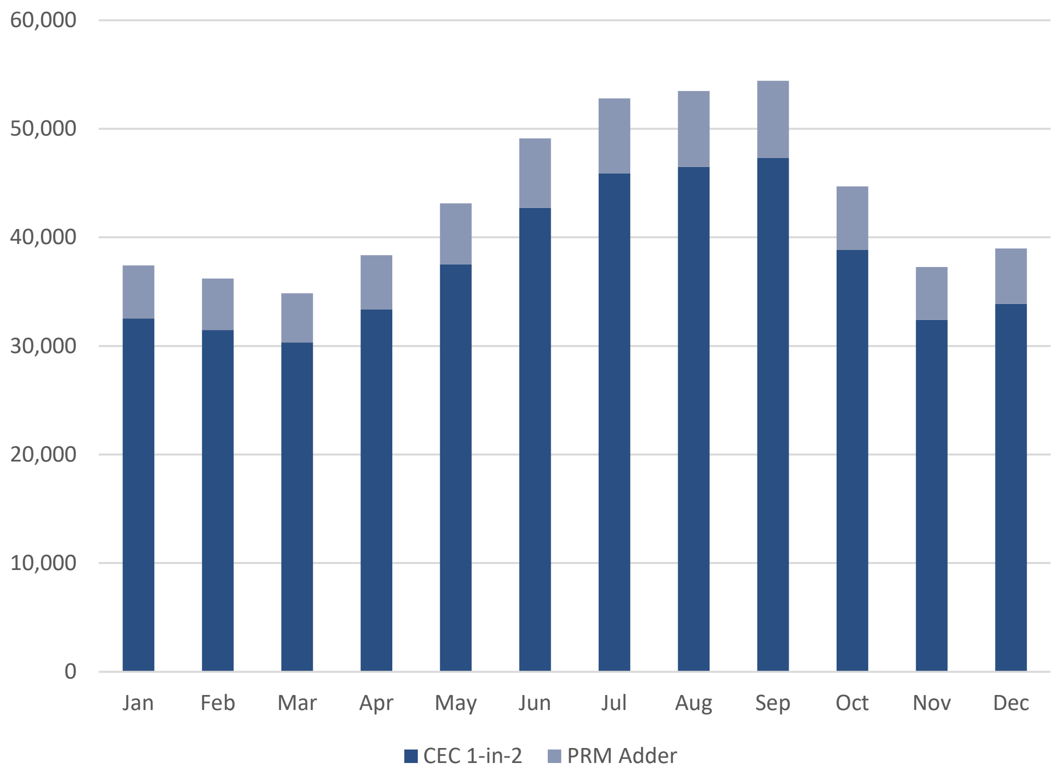
Background: PRM Translation in Slice of Day



Slice of Day PRM Calibration

- Slice of Day PRM translation methods were developed in workshops
- Methods focused on identifying the minimum PRM which would produce a reliable portfolio based on expected resources
- NRDC method and Working Group discussion focused on developing PRM values for each month
  - Addresses 'error' in 1-in-2 load profiles
  - Addresses 'error' in resource counting
  - Provides backstop method to ensure each monthly portfolio meets reliability standard
- NRDC method utilized LOLE study with tuned monthly portfolios; realignment from monthly LOLE to annual LOLE study requires further development

Background: Legacy PRM Approach



Legacy Approach to Monthly PRM

- Legacy PRM (15%-17%) determined through regulatory negotiations in mid-2000s
- Variations in 1-in-2 load result in wide fluctuations in reliability requirement by month
- Monthly requirements not explicitly tethered to reliability modeling

Transition from Monthly to Annual LOLE Study

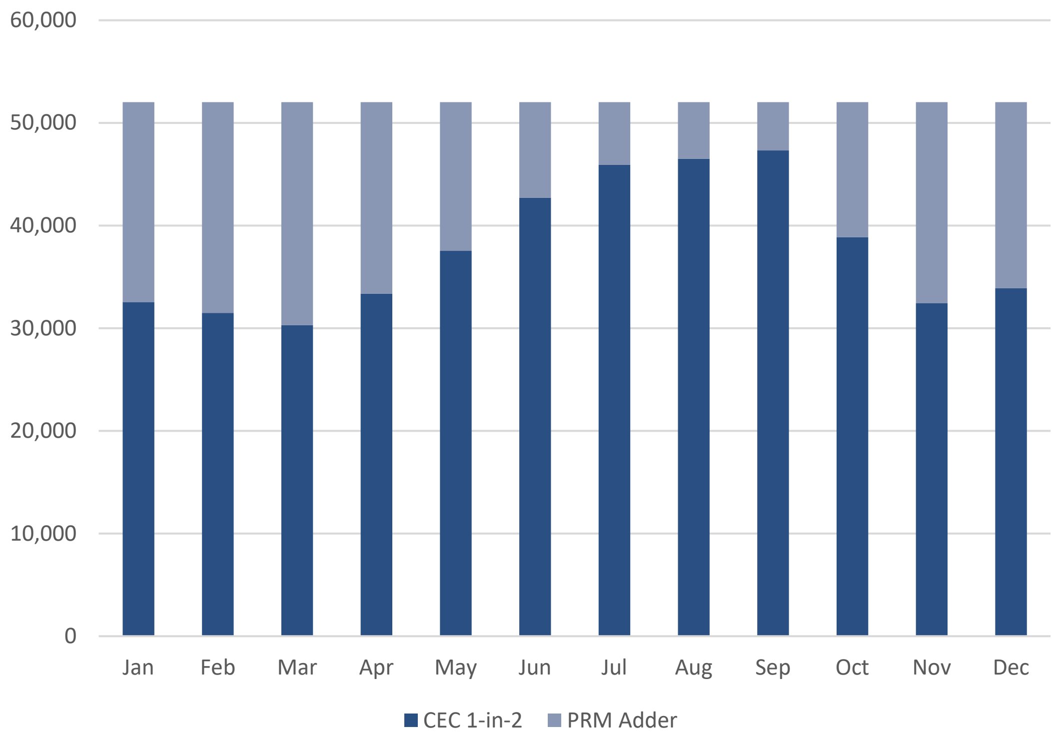
- **Monthly LOLE Studies:** Prior LOLE studies (utilized for ELCC calibration) developed 12 distinct monthly portfolios, each tuned to meet reliability in that month

- **Shift to Annual Study:** Consensus emerged in working groups that monthly LOLE methodology should transition to annual LOLE study (producing single annual portfolio)

- **Impact on PRM Translation:** This transition raised novel questions regarding monthly application of PRM need
  - Should the PRM be a single annual value or calibrated for each month?
  - If single annual value, what value?
  - If multiple values, how should they be set for peak / off-peak months?

*0.1 LOLE = 1 Loss of Load Event-Day in 10 Years

Calibrating PRM to Annual PRM Study

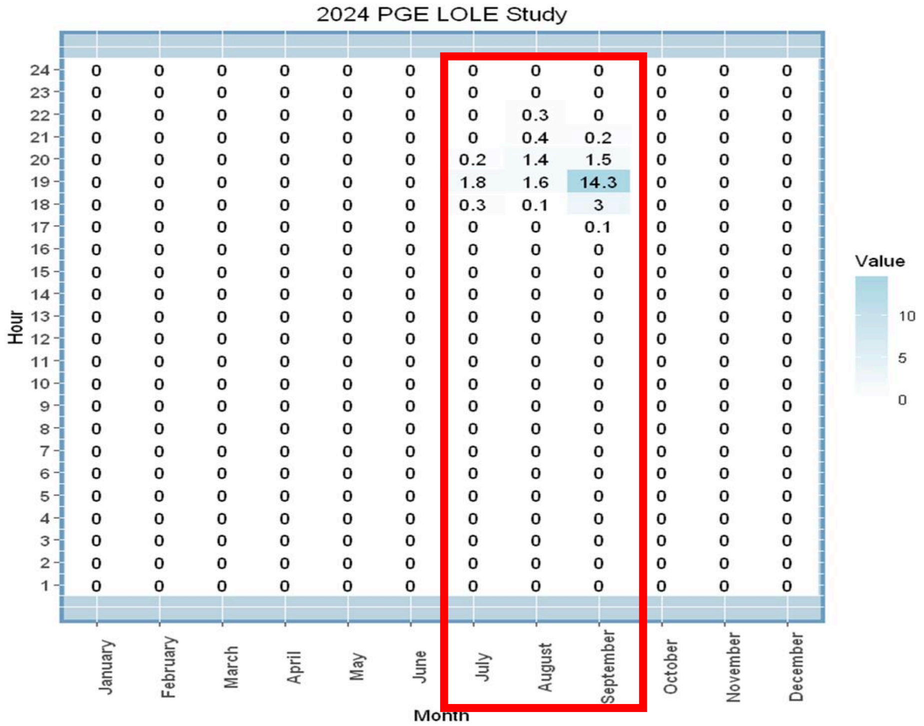


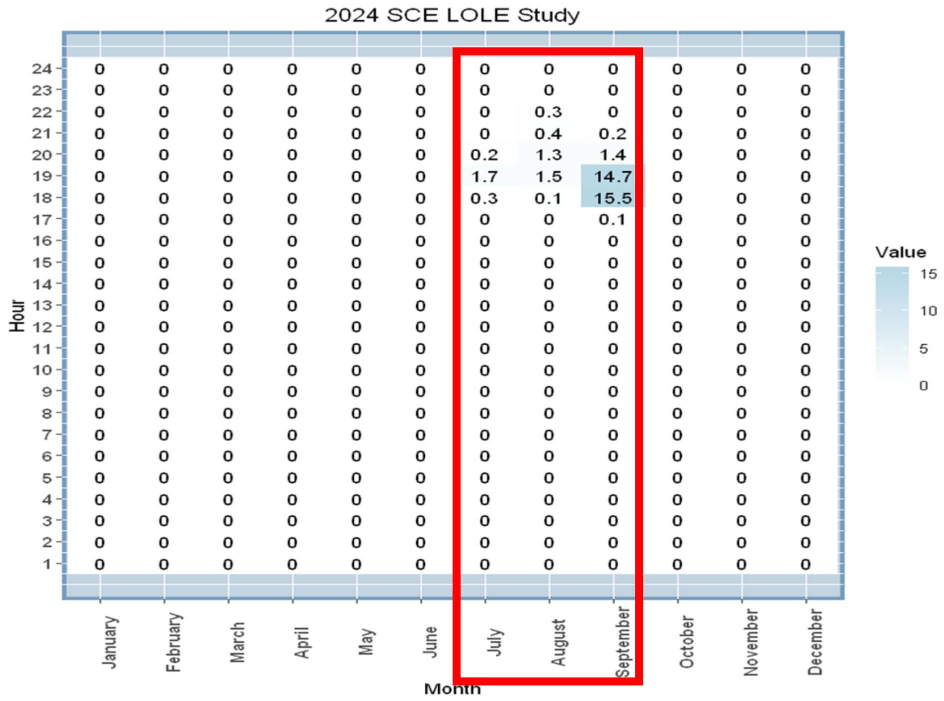
Achieving Annual Portfolio
via PRM Adjustments (Illustrative)

- Annual LOLE study produces single annual portfolio, raising new questions regarding portfolio:
  - Is single annual portfolio desired outcome of RA program?
  - If not, how to tune reliability requirement for each month?
  - Which months merit full portfolio versus reduced requirement?

Monthly PRM Values

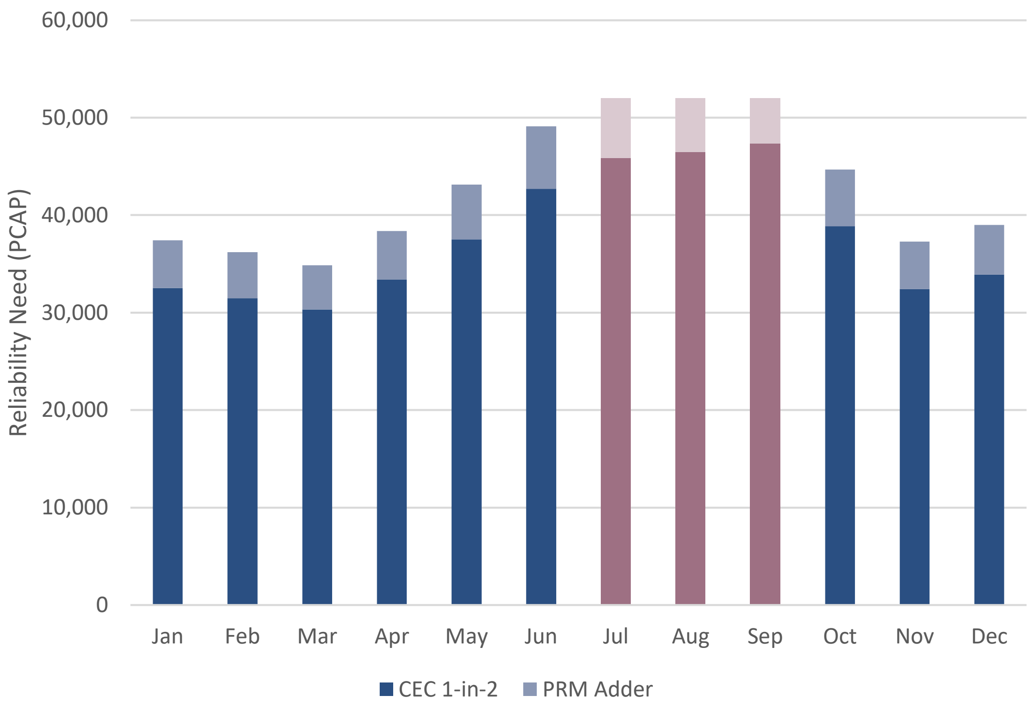
When does LOLE Occur?





- LOLE study results identify need for full annual portfolio in July, August, September
- Reduced PRM / portfolios in July and August likely to result in higher annual LOLE
- Lower portfolio need can be inferred by study results, but magnitude unclear

ACP-CA Monthly PRM Proposal



Illustrative Representation of Monthly PRM Proposal

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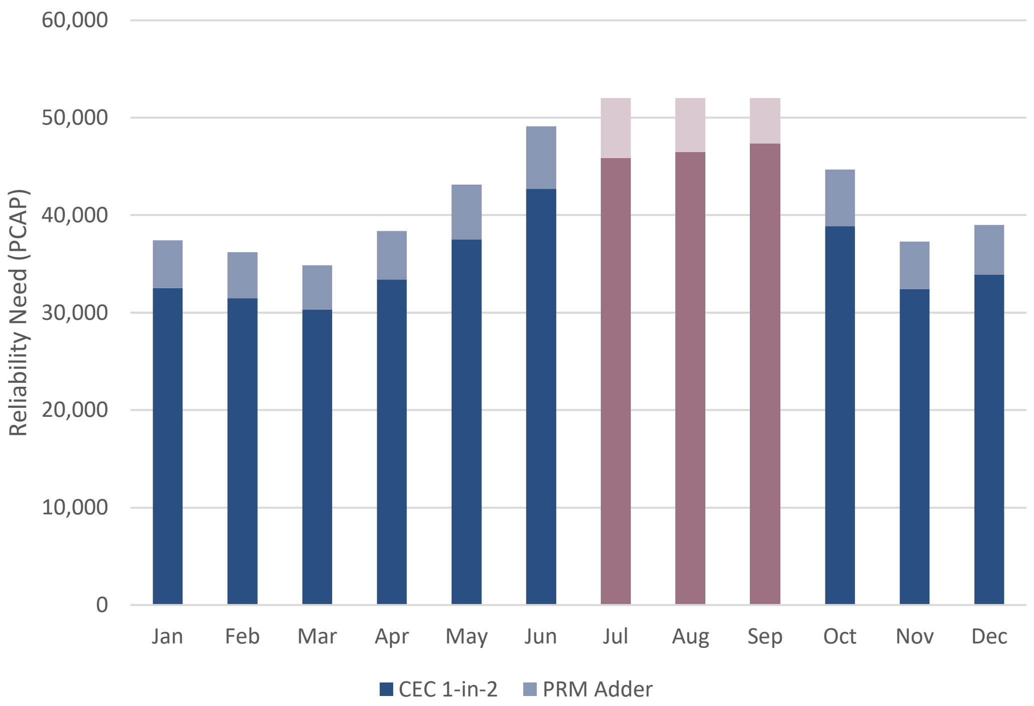
  - October-June
- Stress testing in SERVM to identify and resolve any reliability events introduced by generic off-peak PRM values

ACP-CA Monthly PRM Proposal (Detail)



Illustrative Representation of Monthly PRM Proposal

1. In SERVM, conduct study to identify minimum portfolio meeting 0.1 LOLE across full year, identifying 'peak months' with modeled LOL
2. In Excel, translate portfolio to PRM values for each month using SoD counting rules and load profiles
3. For peak months, set PRM at value identified in Step 2; for off-peak months, set generic PRM value (15-17%)
4. In Excel, construct minimum portfolio for each month necessary to meet monthly PRMs
   - Peak month = annual portfolio
   - Off-Peak months < annual portfolio
5. In SERVM, perform LOLE study with each month constrained to monthly portfolio resources
   - If novel LOL introduced in off-peak months, increment PRM for said month until novel LOL eliminated

Stress Testing

Viability of Single Annual PRM

- Various analyses have emerged showing that single annual PRM is not viable:
  - Single annual PRM inherently results in reliability risk / over-procurement risk in certain critical months

- Most recent study indicates minimum reliable SoD PRMs ranging from 15.4% in September to 29.3% in July
  - If 15% applied in July, novel reliability risk likely introduced, likely significant in magnitude
  - If 29% applied in September, LSEs mandated to procure resources which are unnecessary and likely do not exist

Months	PRM	Managed Peak (MW)	Most Constrained Hour, Hour Ending (HE)
June	34.96%	42,707	19
July	29.27%	45,908	18
August	25.81%	46,500	18
September	15.43%	47,325	19
October	34.37%	38,861	19

Table 2. Monthly SOD-Calibrated PRM Values, Energy Division Staff Proposal

- In addition to the PRM calibration process, efforts should be undertaken to assess how counting rules and load forecast variations drive PRM differentiation across summer months

General Stress Testing Methods

Excel-Based:

- Using PRM Calibration tool, enter proposed PRM values for each month
- Determine minimum monthly portfolios needed to achieve proposed PRM values
- Compare monthly portfolios with baseline portfolio (annual portfolio assessed in SERVM)
- If peak month portfolios differ markedly from baseline portfolio, too high/too low errors likely exist

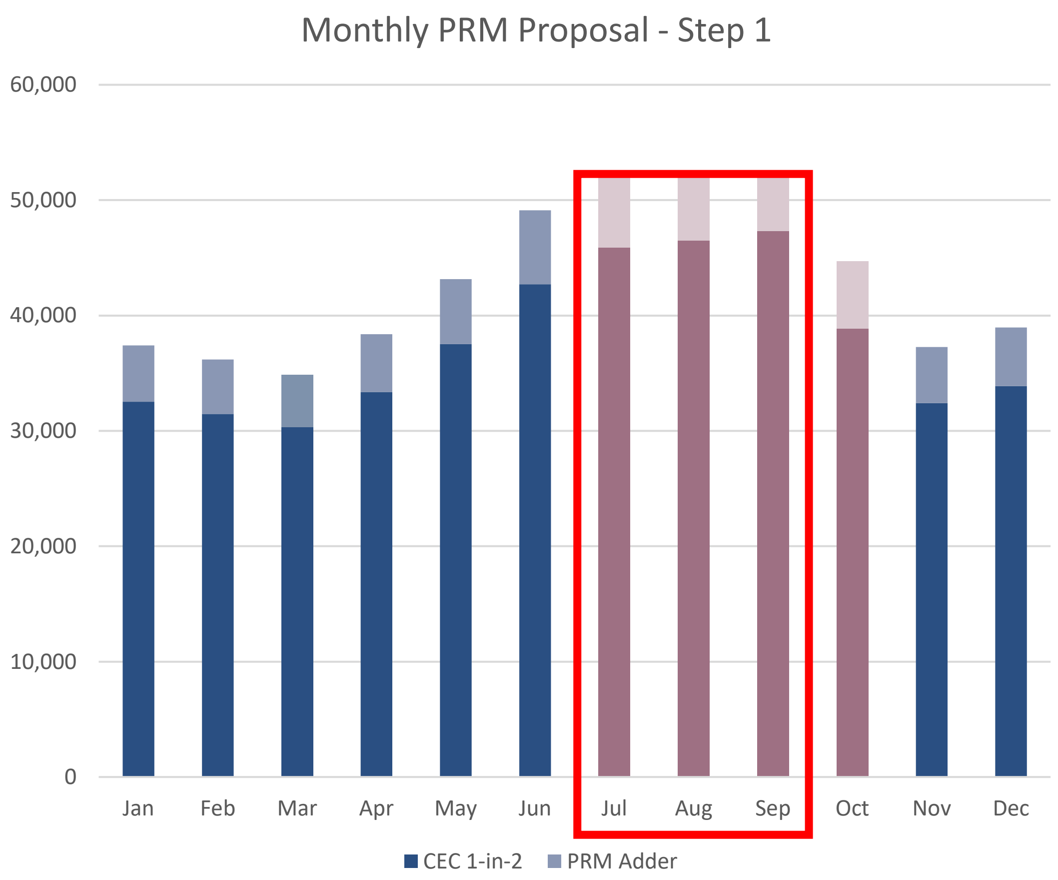
Concerns may be identified if the portfolio required for an at-risk month is considerably smaller or larger than the annual portfolio

SERVM-Based:

- Using PRM Calibration tool, enter proposed PRM values for each month
- Determine minimum monthly portfolios needed to achieve proposed PRM values
- Enter monthly portfolios into SERVM for annual reliability analysis
- If SERVM LOL results differ markedly from baseline portfolio (in aggregate and by month), too high/too low errors likely exist

Concerns may be identified through robust probabilistic analysis of the resulting monthly portfolios

Stress Testing for Monthly PRM Proposal



- Reprocess implied portfolios through SERVM
- Peak months should have equivalent LOLE (peak month portfolios = annual reliable portfolio)
- If off-peak month experiences LOL, increment PRM for that month until zero LOL in that month
- Example:
  - 15% PRM in October introduces novel LOL
  - Increment October PRM to 15.5%, 16%, 16.5% and stress test LOL events constrained to initially identified at-risk months

Next Steps

Options for 2025 Compliance Year

- CPUC can resolve PRM calibration concerns prior to 2025 Compliance Year
  - 15.4% PRM would result in reliability risk in July (29%), August (26%)
  - 17% PRM would result in reliability risk in July (29%), August (26%) + unnecessary (and unavailable) procurement in September (15%)

- No additional SERVM analysis is needed to calibrate PRMs for critical summer months, but support additional transparency and vetting of prior LOLE study and PRM translation process

- Additional SERVM analysis would be beneficial to stress test options and finalize path forward

Policy and Implementation Questions + Straw Proposals

- What is desired RA portfolio across months?
  - Straw Proposal:
    - Full annual portfolio for ‘at risk’ months (July, August, September)
    - Lower portfolio with generic PRM for off-peak months (needs add’l development)

- How should stress testing be performed?
  - Straw Proposal:
    - Two-pronged Excel and SERVM-based approaches with adjustments for PRMs which drive over- or under-procurement in critical months, novel LOL in off-peak months

*0.1 LOLE = 1 Loss of Load Event-Day in 10 Years

Parallel PRM Refinement Initiatives

- PRM should be 'last resort' – blunt tool for fine-grain calibration of RA program

- Parallel efforts to squeeze 'PRM error' into other parameters should be pursued:
  - Alignment of hourly profiles for resources aligned with probabilistic valuations (e.g. ELCC)
  - Inclusion of probabilistic outage impacts in resource counting
  - Incorporation of energy limits (e.g. hydro, imports) in resource counting
  - Alignment of compliance load profiles with expected load shapes on risk days, not 1-in-2

- Aligning resource parameters with probabilistic modeling improves fidelity, reduces error, and improves year-to-year program stability and predictability

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Appendix

Working Group Consensus

- **Consensus Steps:**
  - **Develop Portfolio:** Utilizing SERVM, adjust baseline portfolio by incrementing or decrementing firm resources until portfolio meets desired 0.1 LOLE* standard
    - **Single Annual Portfolio:** Discussions led to general consensus on need to shift from monthly LOLE study with LOLE allocated across months to determination of single portfolio needed for reliability across year
  - **Translate Portfolio to PRM:** Utilizing Excel, determine PRM implied by resource portfolio with adopted monthly load profiles and resource counting rules
- **Non-Consensus/Unresolved Steps:**
  - **Annual/Monthly:**
    - How should single annual portfolio be translated into monthly requirements?
    - Should PRM translation be done for a single month (annual PRM) or for all months (monthly PRM)?
    - What requirements should be set during off-peak months?
  - **Stress Testing:** What stress tests are necessary to ensure reliability of selected PRM across the year?
- Working Group Report, p. 114-131

*0.1 LOLE = 1 Loss of Load Event-Day in 10 Years

TRACK 1 PROPOSALS

R.23-10-011
Workshop Presentation
February 14, 2024

WPTF WESTERN POWER TRADING FORUM

2025 PRM CALCULATION

WPTF WESTERN POWER TRADING FORUM

- Problem: Simply applying selected PRM to all months does not ensure system reliability over entire compliance year
- Solution: Stress testing and PRM adjustments
- WPTF Proposal (assumes single PRM for all months):
  1. Start with resource portfolio that achieves annual 0.1 LOLE
  2. Translate portfolio to SOD framework
  3. Calculate resulting PRM for tightest month with LOLE (September)
  4. Apply selected PRM to all months
  5. Run resulting portfolio through SERVM to test annual reliability
  6. If annual LOLE > 0.1, increase PRM and repeat Step 5.

CPE "SOFT PRICE CAP"

- Problem: No objective standard for "unreasonably high" bid prices (local waiver trigger?)
  - CPEs have unchecked discretion to reject bids based on price
  - Effectively forces LSEs into backstop role
  - Increases probability of CAISO backstop being needed
- WPTF Proposal:
  - Adopt CPE "soft price cap" equal to sum of RA penalty and CPM "soft offer cap"
  - Allow CPE to reject bids priced at or below soft price cap, provided it has no procurement deficiencies
  - Allow CPE to accept bids above soft price cap, provided it demonstrates doing so is in ratepayers' best interest
- Alternative: Make CPEs subject to RA penalties

RA Slice-of-Day Hourly Transactability Proposal

Resource Adequacy Track 1 Proposal Workshop

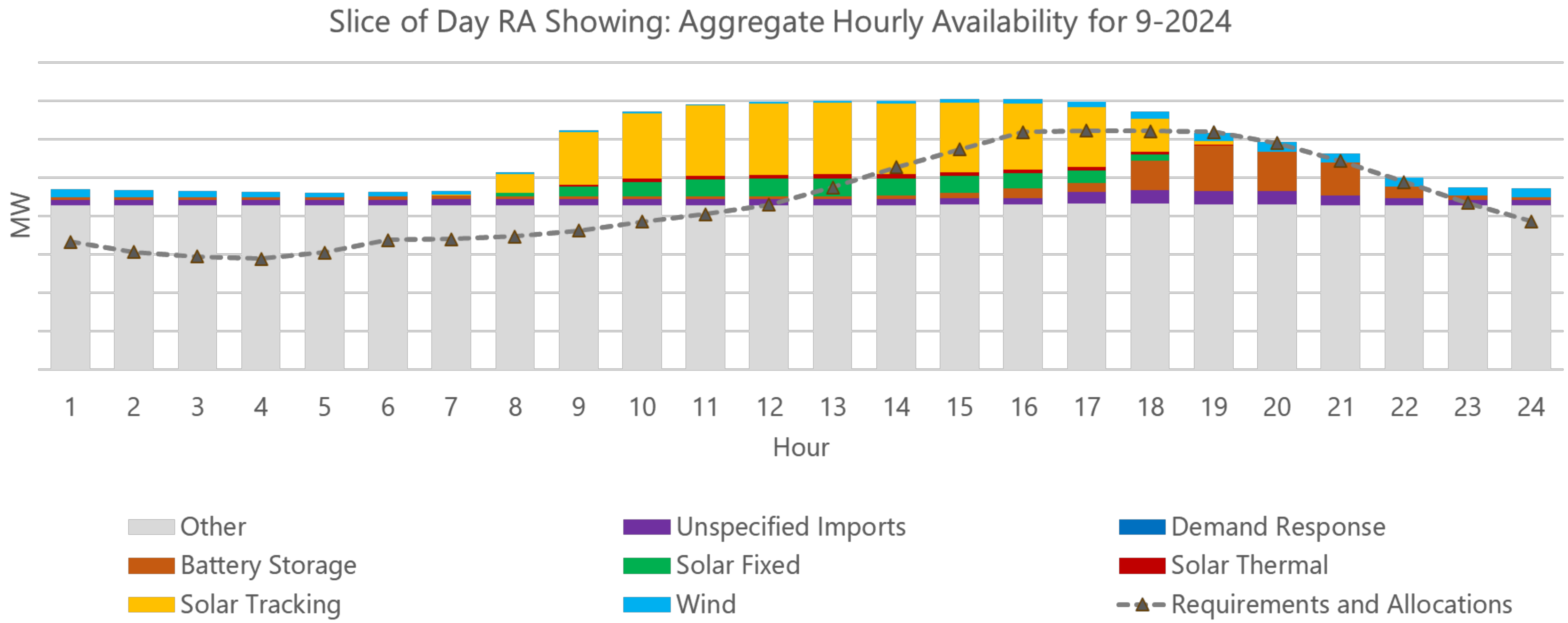
February 14, 2024

Slice-of-Day Transactability Background

- Despite setting 24 requirements and 24 NQC values, D.22-06-050 requires LSEs to continue to transact resources monthly
  - × Creates artificial RA market scarcity in an already tight RA market
  - × Further impedes compliance and cost-effective procurement

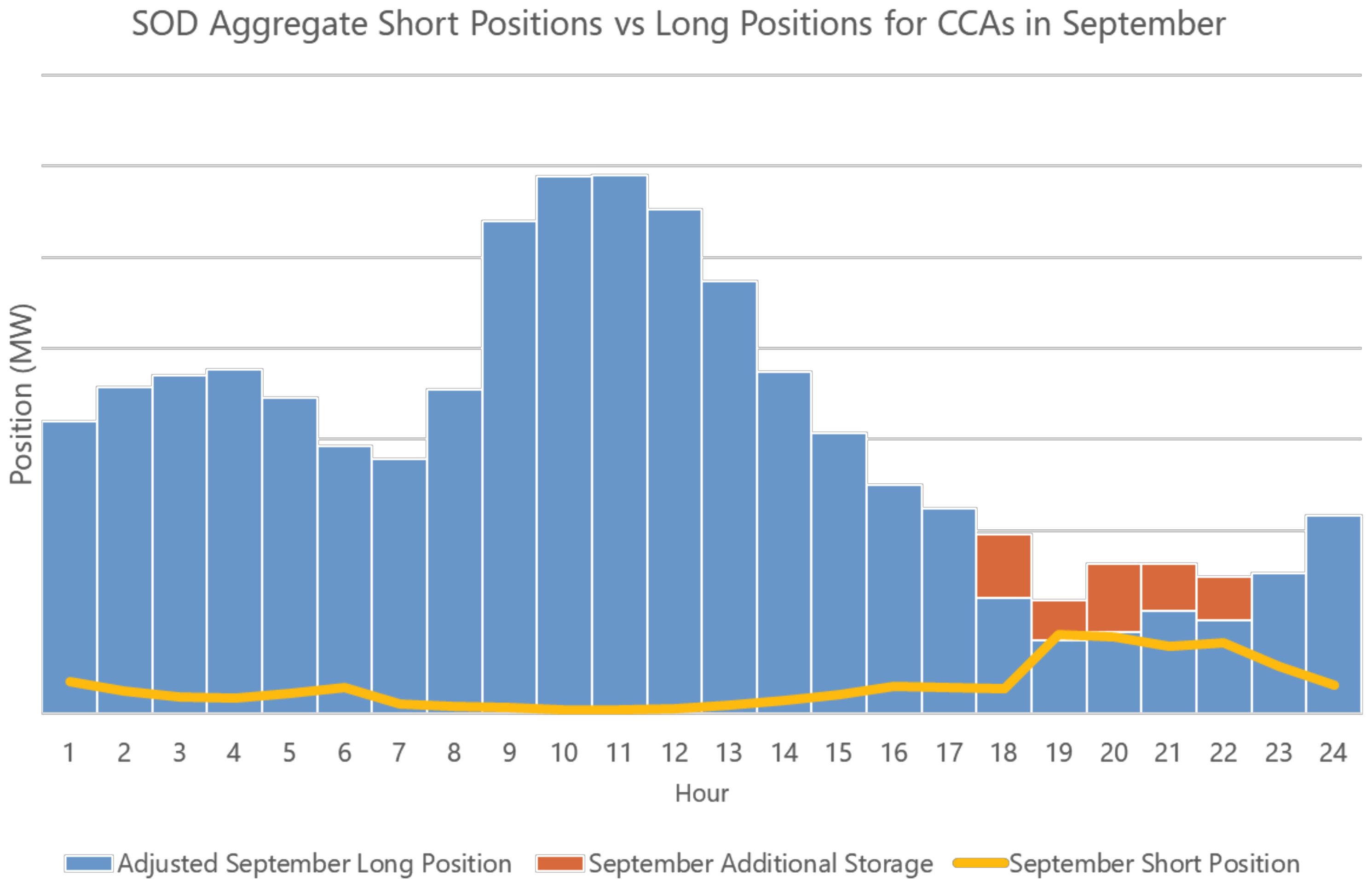
- D.22-06-050 found that if "transactability and inefficiency" issues arise due to the inability to transact hourly, then the Commission may consider hourly load obligation trading

CCA SOD Aggregate Year-Ahead Showing, As Filed, for September



CCAs Could Meet Requirements in Aggregate, Even If Individual CCAs Were Short in Some Hours

- Short Position shows individual CCAs did not meet requirements in many hours
- Long Position shows other CCAs were long in all hours (blue) and could have shown more storage (red)
- Aggregate of CCA portfolios could meet requirements, implying that trading between CCAs would eliminate shortages

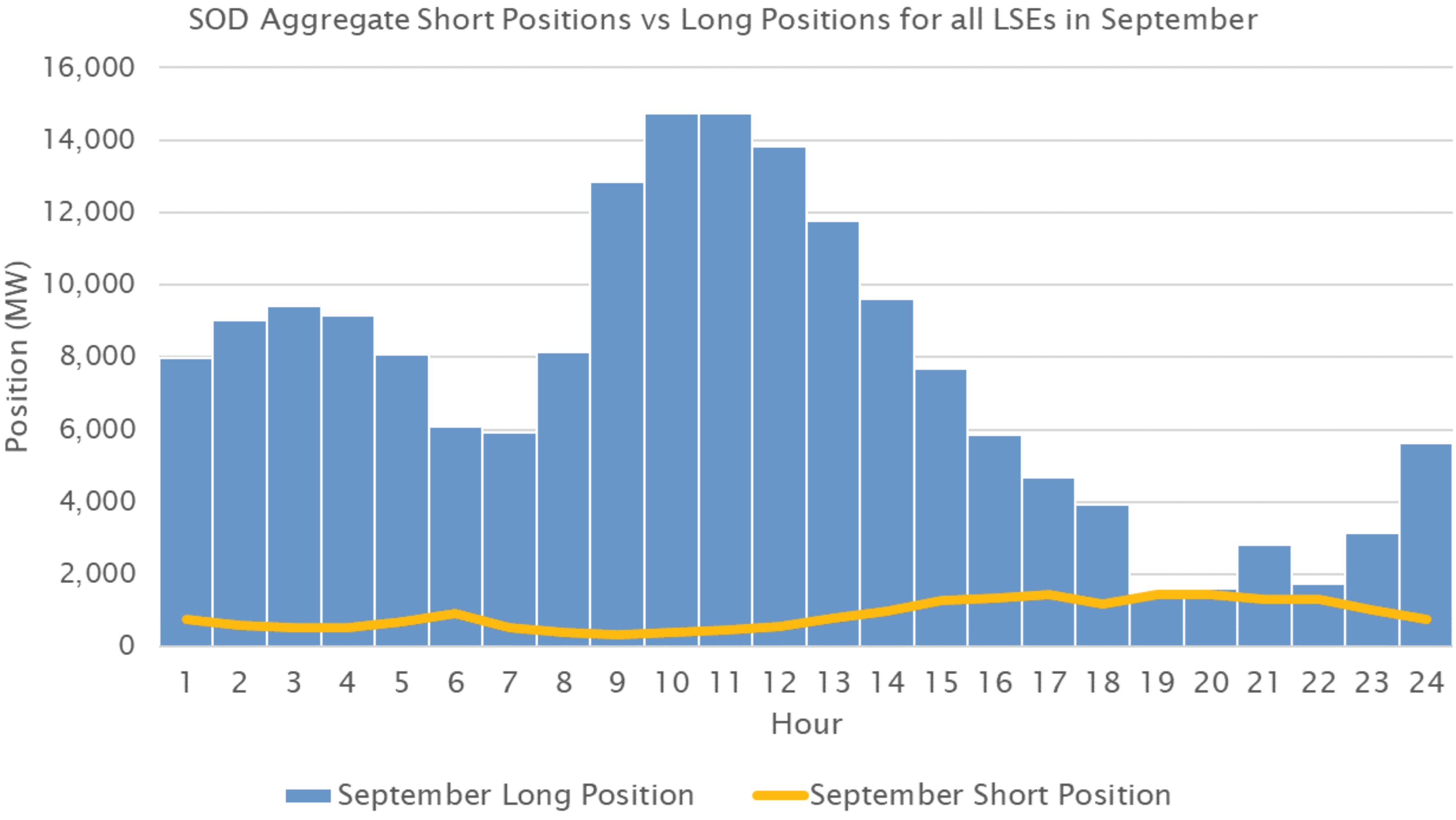


CALCCA ADVANCING LOCAL ENERGY CHOICE

Source: CalCCA analysis of CCA SOD YARA filings submitted to the CPUC

CPUC Analysis of all LSE YARA Filings Is Consistent with CalCCA Analysis of CCA Filings

- Long Positions exceed Short Positions in aggregate for all hours except HE19
- Consistent with CalCCA's findings, trading between LSEs could eliminate nearly all deficiencies
- CPUC should reoptimize storage showings to see if HE19 deficiencies could be eliminated



Source: CPUC Report on Resource Adequacy Slide of Day Implementation and Year Ahead Showings (February 2024), Table 13. Aggregate 2024 Slice of Day Year Ahead Showings for September.

Adopt Hourly Load Obligation Trading

Administratively simple

- LSE paying another to take on its obligation would represent the trade as a MW increase to its RA resource portfolio
- The LSE receiving payment to take on the obligation would represent the trade as a MW decrease in its RA resource portfolio

NOT Unbundling

- Leaves the obligations and requirements of generators unaffected
- Eliminates need to modify CAISO processes like substitution, or must-offer obligations

More effective

- Swaps have too much market friction involved for them to provide significant benefits under SOD
- Swaps may require multiple layers of swaps for each LSE to reach compliance.

Maintains LSE Responsibility

- All LSEs remain responsible for serving their load and providing RA for their customers
- LSEs would compensate those LSEs that take on portions of their load. Both LSEs involved in an hourly load obligation trade would need to submit RA plans documenting the trade

Example Showing (1 of 2)

Represented as a Sale or Purchase of Load (At a Negative Price) in the Showing Tool

LSE Showing Tab

- For the LSE taking on RA obligation

Contract ID	Resource ID	Resource SubID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket 4	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	FALSE
CAM Storage	CAM Storage Allocation Multi Cycle		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	FALSE
CAM Peakers	CAM Peaker Allocation		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	TRUE
Purchase of Load	Name of LSE Selling Load										FALSE

- For the LSE selling their RA obligation

Contract ID	Resource ID	Resource SubID	NQC Under Contract (MW)	Local RA (MW)	Committed Flexible RA (MW)	Capacity Effective Start Date	Capacity Effective End Date	SCID or Counterparty if not available	MCC Bucket	Unspecified Import	Use Default Profile
CAM Storage	CAM Storage Allocation Single Cycle		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	FALSE
CAM Storage	CAM Storage Allocation Multi Cycle		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	FALSE
CAM Peakers	CAM Peaker Allocation		0	0	0	#NUM!	1900-01-31	TEST	FALSE	FALSE	TRUE
Sale of Load	Name of LSE Purchasing Load										FALSE

Example Showing (2 of 2)

Represented as a Sale or Purchase of Load (At a Negative Price) in the Showing Tool

Resource Custom Profiles Tab

- For the LSE taking on RA obligation

Resource ID	Resource SubID	MW HE 1	MW HE 2	MW HE 3	MW HE 4	MW HE 5	MW HE 6	MW HE 7	MW HE 8	MW HE 9	MW HE 10	MW HE 11	MW HE 12	MW HE 13	MW HE 14	MW HE 15	MW HE 16	MW HE 17	MW HE 18	MW HE 19	MW HE 20	MW HE 21	MW HE 22	MW HE 23	MW HE 24
Name of LSE Selling Load																				-10	-10				

- For the LSE selling their RA obligation

Resource ID	Resource SubID	MW HE 1	MW HE 2	MW HE 3	MW HE 4	MW HE 5	MW HE 6	MW HE 7	MW HE 8	MW HE 9	MW HE 10	MW HE 11	MW HE 12	MW HE 13	MW HE 14	MW HE 15	MW HE 16	MW HE 17	MW HE 18	MW HE 19	MW HE 20	MW HE 21	MW HE 22	MW HE 23	MW HE 24
Name of LSE Purchasing Load																				10	10				

CPUC Validation

- Filter Resource Custom Profiles tab for load sales and purchases, aggregate, and ensure total across all LSEs equals zero

Hourly Availability Chart

- Label load sales and purchases as Requirements and Allocations on LSE Showing Complete Tab

Staff Proposal for UCAP Framework

Determining and Applying Forced Outage Rates for Resource Adequacy

February 14, 2024

Presented by Robert Hansen

Senior Utilities Engineer

Resource Modeling Team

California Public
Utilities Commission

Outline

- Coordination with CAISO
- Thermal Powerplants
  - EFORd from GADS
  - Additional deration for ambient temperatures
- Battery Energy Storage Systems
  - Estimating EFOR based on Curtailment Reports
- Results
- Questions

CAISO Coordination

Reconciling GADS and CAISO data and Standardizing

CAISO Coordination

- CAISO had proposed a UCAP framework previously
- CPUC and CAISO intend to coordinate developing a consistent UCAP framework for use across proceedings and markets
- There are obstacles to full implementation, including data availability and existing incentive structures

Expected Outcomes

- Better modeling of capacity availability in Resource Adequacy
- Improve alignment of policy and incentives

UCAP for Thermal Powerplants

Combustion Turbine and Combined Cycle

UCAP for Thermal Powerplants

Two Main Components:

- EFORd from GADS data
- Monthly Ambient Derates based on CAISO curtailment reports

Concerns:

- GADS data confidentiality

UCAP for Thermal Powerplants

EFORd Aggregation

- Resources are grouped into 0-25th, 25th-75th, or 75th-100th percentile ranges, based on their overall median EFORd from 2020-2022
- Capacity-weighted monthly EFORd values are calculated for each percentile group

UCAP for Thermal Powerplants

Derates due to Ambient Temperatures

- Analyzed reported curtailments to model FORCED AMBIENT_DUE_TO_TEMPERATURE as function of temperature
- Model is applied to two unit types and 12 weather stations
- Model can be used with Climate-Informed Forecasts to predict derates in future climates
- For UCAP, used median derates under current-climate conditions for each unit type and weather station

Results with New Methodology

- Revised Slopes by Unit Type:
  - Combustion Turbine: $\beta_1 = \frac{0.138\%}{°C}$
  - Combined Cycle: $\beta_1 = \frac{0.097\%}{°C}$
  - Revised intercepts vary by Unit Type and Weather Station
- Median derated capacities in current climate across all years and weather stations:

	Original	Revised
Combustion Turbine	95.77%	98.15%
Combined Cycle	96.18%	98.70%

UCAP for Thermal Powerplants

Definition of EFORd from GADS:

$$EFORd = \frac{FOHd + EFDHd}{SH + FOHd}$$

Where

$$FOHd = Forced\ Outage\ Hrs\ during\ Demand$$

$$EFDHD = Equivalent\ Forced\ Outage\ Hrs\ during\ Demand$$

$$= EFDH - EFDHRS$$

$$SH = Service\ Hrs$$

$$EFDH = Equivalent\ Force\ Outage\ Hrs$$

$$= \frac{Deration\ Hrs \times Size\ of\ Reduction}{Net\ Maximum\ Capacity}$$

$$EDFHRS = \frac{Deration\ Hrs\ during\ Reserve\ Shutdowns \times Size\ of\ Reduction}{Net\ Maximum\ Capacity}$$

Updated Methodology for Derating Thermal Powerplants due to Ambient Temperature

Changes to the originally proposed derating

History of this proposal and objective of this presentation

- Staff presented a methodology for derating thermal powerplants each hour based on hourly temperature in March 2023
- Stakeholders submitted comments and questions, which resulted in very helpful dialogue and led to an improved methodology.

Revised methodology:

- Zero curtailment (i.e., full capacity) is now assumed for unreported hours
- Apply multilinear regression rather than single variable regressions in two-steps
  - Create boolean variables to define categories
  - Each weather station becomes a variable for regression which can both be either 0 or 1
  - Allows more data to be included in analysis
  - Each unit type is analyzed separately, yielding different best-fit curves

Updated Methodology

For each unit type, we find the least-squares optimal regression parameters to fit the model:

$$D_i = \beta_1 T_i^* + \beta_{3.1} W_1 + \beta_{3.2} W_2 + \cdots + \beta_{3.n} W_n + \beta_4$$

D_i	is the reported or imputed derate percentage for observation i
T_i^*	is the recorded temperature of the nearest weather station at the time of observation i normalized for resource
W_j	is the j^{th} Boolean variable indicating the weather station closest to the resource associated with observation i, with exactly one of n
β_k	is a linear regression parameter applied to the k^{th} of the $2 + n$ variables

Updated Methodology

The regression parameter for temperature is then applied to piecewise-linear model for each class, consisting of a weather station and a unit type

$$\widehat{D}_i = \begin{cases} 100\% & |T_i \leq T_0 \\ 100\% - \beta_1(T_i - T_0) & |T_i > T_0 \end{cases}$$

This aspect of the model is unchanged from the previous version.

Updated Methodology

- The derate model was applied to the current-climate weather year to produce hourly derations for each unit type and weather station
- Monthly outage rates are the median hourly deration percentage due to ambient temperature throughout the month

UFOR for Thermal Resources

Results

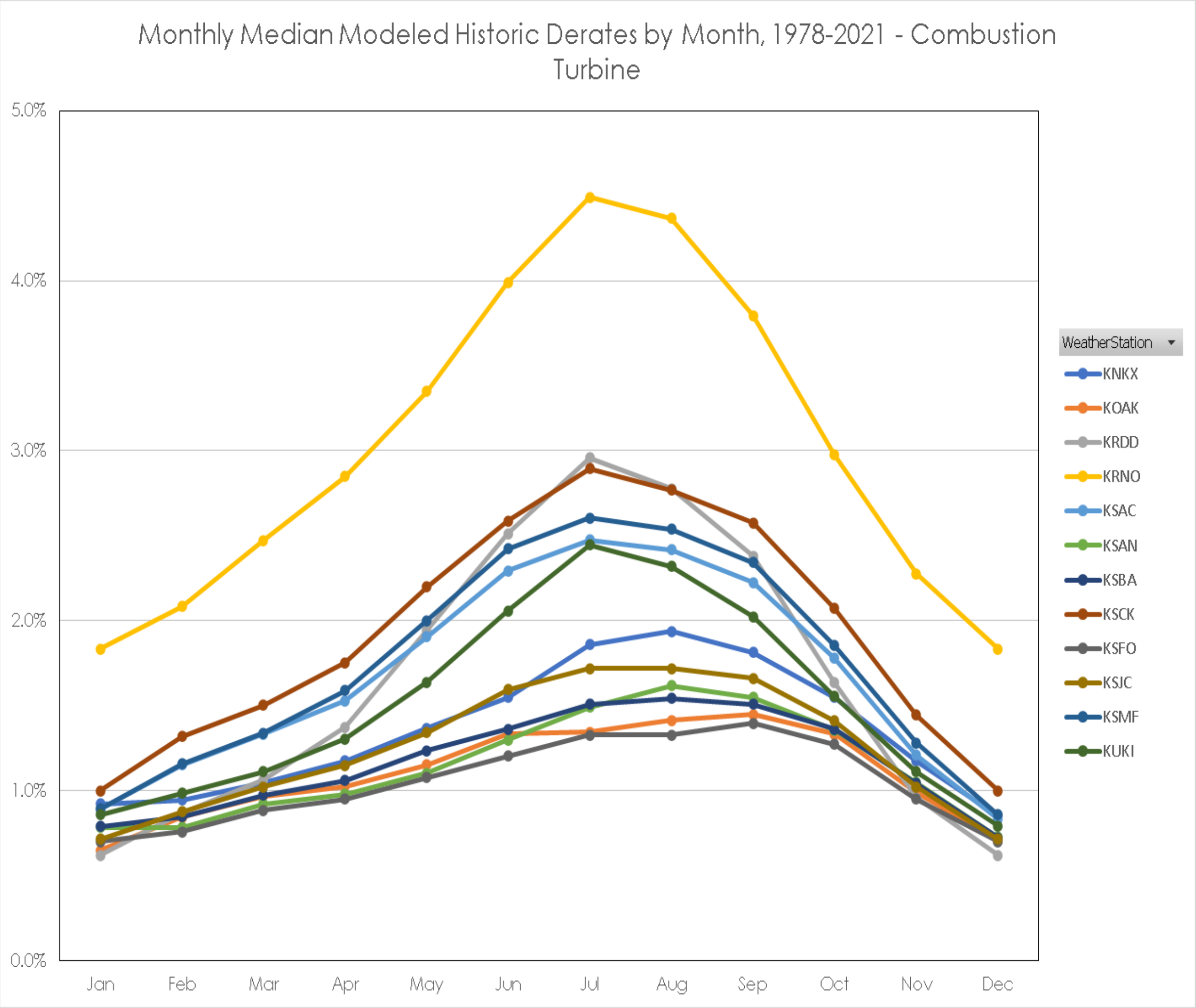
EFORd Categories

- Aggregate EFORd Values may be confidential
- EFORd Categories determined based on year-round median EFORd for each resource
    - 0-1st quartile within each Unit Type → "Low"
    - 1st-3rd quartile → "Mid"
    - 3rd-4th quartile → "High"

Unit Type	EFORd Category	Resource Count
CC Block	Low	4
CC Block	Mid	6
CC Block	High	3
CC GT	Low	9
CC GT	Mid	16
CC GT	High	8
CC Steam	Low	4
CC Steam	Mid	7
CC Steam	High	4
Diesel	Low	3
Diesel	Mid	4
Diesel	High	3
GT	Low	13
GT	Mid	24
GT	High	13

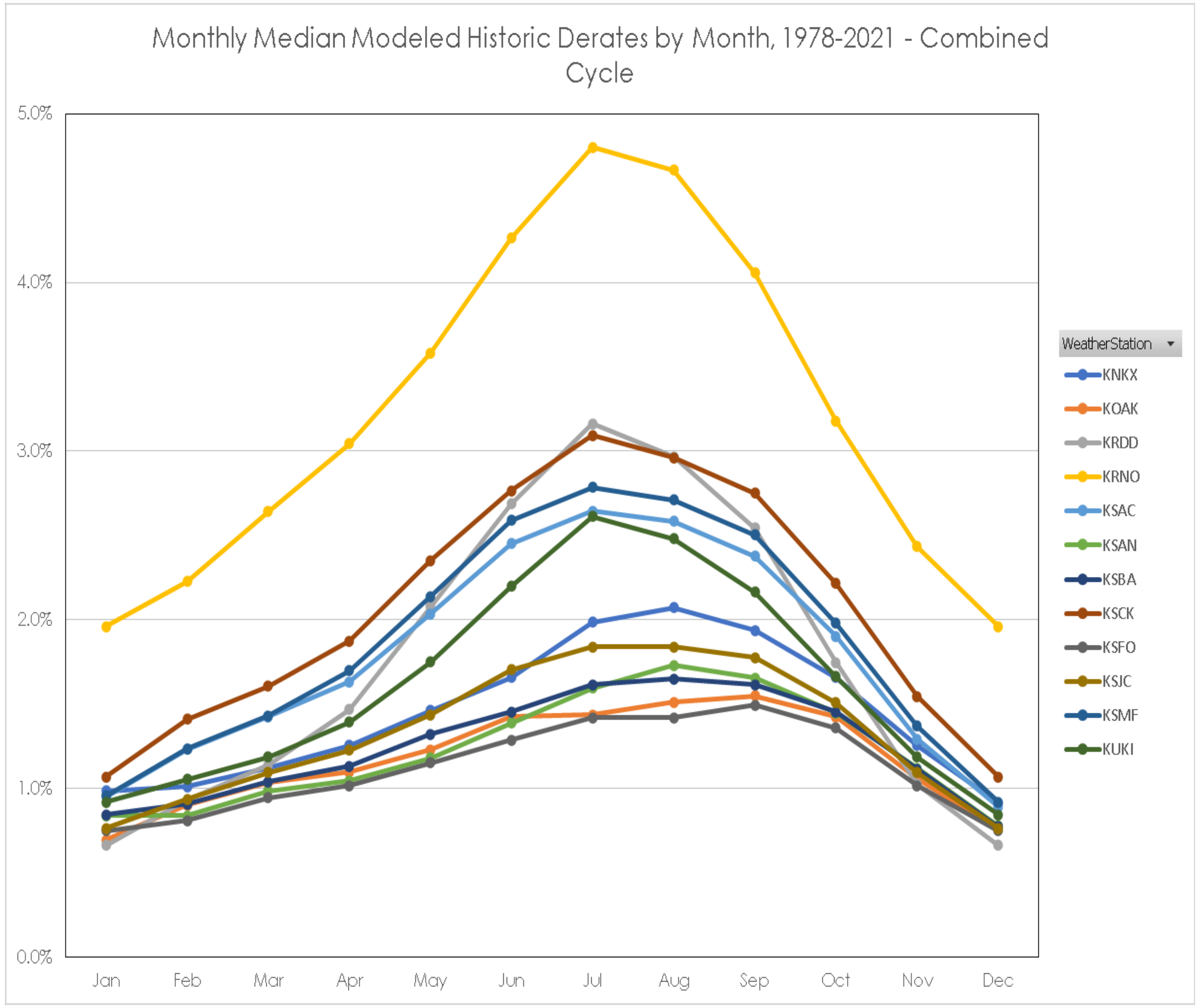
Ambient Deration – Combustion Turbine

	Weather Station ID											
Month	**KNKX**	**KOAK**	**KRDD**	**KRNO**	**KSAC**	**KSAN**	**KSBA**	**KSCK**	**KSFO**	**KSJC**	**KSMF**	**KUKI**
Jan	0.92%	0.65%	0.62%	1.83%	0.89%	0.78%	0.79%	1.00%	0.70%	0.72%	0.89%	0.86%
Feb	0.95%	0.84%	0.87%	2.08%	1.15%	0.78%	0.85%	1.32%	0.76%	0.88%	1.16%	0.99%
Mar	1.05%	0.97%	1.06%	2.47%	1.33%	0.92%	0.97%	1.50%	0.88%	1.02%	1.34%	1.11%
Apr	1.17%	1.03%	1.37%	2.85%	1.53%	0.98%	1.06%	1.75%	0.95%	1.15%	1.59%	1.30%
May	1.37%	1.15%	1.94%	3.35%	1.90%	1.10%	1.24%	2.20%	1.08%	1.34%	2.00%	1.64%
Jun	1.55%	1.33%	2.51%	3.99%	2.29%	1.30%	1.36%	2.59%	1.20%	1.59%	2.42%	2.06%
Jul	1.86%	1.35%	2.96%	4.49%	2.48%	1.49%	1.51%	2.89%	1.33%	1.72%	2.61%	2.45%
Aug	1.94%	1.41%	2.78%	4.37%	2.42%	1.62%	1.54%	2.77%	1.33%	1.72%	2.54%	2.32%
Sep	1.81%	1.45%	2.38%	3.80%	2.22%	1.55%	1.51%	2.57%	1.40%	1.66%	2.34%	2.02%
Oct	1.55%	1.33%	1.63%	2.97%	1.78%	1.36%	1.36%	2.07%	1.27%	1.41%	1.85%	1.56%
Nov	1.17%	0.99%	0.96%	2.28%	1.21%	1.05%	1.04%	1.45%	0.95%	1.02%	1.28%	1.11%
Dec	0.85%	0.71%	0.62%	1.83%	0.83%	0.73%	0.72%	1.00%	0.70%	0.72%	0.86%	0.79%



Ambient Deration – Combined Cycle Blocks

	Weather Station ID											
Month	**KNKX**	**KOAK**	**KRDD**	**KRNO**	**KSAC**	**KSAN**	**KSBA**	**KSCK**	**KSFO**	**KSJC**	**KSMF**	**KUKI**
Jan	0.99%	0.69%	0.66%	1.96%	0.95%	0.84%	0.85%	1.07%	0.75%	0.76%	0.96%	0.92%
Feb	1.01%	0.90%	0.93%	2.23%	1.23%	0.84%	0.91%	1.41%	0.81%	0.94%	1.24%	1.05%
Mar	1.12%	1.04%	1.14%	2.64%	1.43%	0.99%	1.04%	1.61%	0.94%	1.09%	1.43%	1.19%
Apr	1.25%	1.10%	1.47%	3.04%	1.63%	1.05%	1.13%	1.87%	1.02%	1.23%	1.70%	1.39%
May	1.46%	1.23%	2.08%	3.58%	2.04%	1.18%	1.32%	2.35%	1.15%	1.44%	2.14%	1.75%
Jun	1.66%	1.43%	2.69%	4.26%	2.45%	1.39%	1.46%	2.76%	1.29%	1.70%	2.59%	2.20%
Jul	1.99%	1.44%	3.16%	4.80%	2.65%	1.60%	1.61%	3.09%	1.42%	1.84%	2.79%	2.61%
Aug	2.07%	1.51%	2.97%	4.67%	2.58%	1.73%	1.65%	2.96%	1.42%	1.84%	2.71%	2.48%
Sep	1.94%	1.55%	2.54%	4.06%	2.38%	1.66%	1.61%	2.75%	1.49%	1.78%	2.50%	2.16%
Oct	1.66%	1.43%	1.75%	3.18%	1.90%	1.45%	1.46%	2.22%	1.36%	1.51%	1.98%	1.66%
Nov	1.25%	1.06%	1.02%	2.43%	1.29%	1.12%	1.11%	1.55%	1.02%	1.09%	1.37%	1.19%
Dec	0.91%	0.76%	0.66%	1.96%	0.89%	0.78%	0.77%	1.07%	0.75%	0.76%	0.92%	0.85%



UFOR from EFORd and Ambient Derates

- UFOR values evaluated on a monthly basis for each resource
- Each resource would be assigned an ambient derate based on its unit type and nearest weather station, and an EFORd category based on its historic performance
- Each resource's UFOR values are the sum of the associated EFORd + median ambient deration multiplied by the resource's capacity for each month.

UCAP for Battery Energy Storage Systems

Estimating EFOR from CAISO curtailment reports, not GADS

UFOR for Battery Energy Storage Systems

Remaining Issues

Remaining Issues for Storage UCAP

- EFOR Denominator
  - Where to find or how to estimate Reserve Shutdowns and Charging Hours?
  - Assume 4 hours or other fixed charging time each day?
  - Expect EFOR to increase with any change.
- Cause Code Equivalency
  - Do any curtailments marked "Planned" count toward Forced Outage Rate?
  - Which Nature-of-Work values should be included in EFOR numerator and denominator?
- Resource Aggregation
  - Is aggregation necessary, or are resource-level monthly EFOR preferrable?

Remaining Issues for Storage UCAP

- All results are preliminary
- We request stakeholder feedback on these issues and any other concerns

UFOR for Battery Energy Storage Systems

Methodology

UCAP for Battery Energy Storage Systems

- Preliminary Approach and Results
- GADS database does not yet include battery resources
- As alternative, we propose developing UCAP values based on CAISO's Prior Trade Day Curtailment Reports
- Key Limitations:
  - Storage resources are new, so only a few years of data is available
  - Curtailment reports don't include data on reserve shutdowns or charging hours

Curtailment Reports vs. GADS

Comparing GADS vs. CAISO data:

- GADS outages include a Unit Code associated with the resource, Event Type, and Cause Code indicating the reason for the outage
- CAISO curtailments are reported by Resource ID, Outage ID, Outage Type, and Nature-of-Work
- 100s of cause codes vs. 10s of combinations of Outage Type and Nature-of-Work
- Mapping CAISO curtailments to GADS outages is not straightforward

GADS Cause Codes for Combined Cycle

- PLANT_TROUBLE
- NEW_GENERATOR_TEST_ENERGY
- TRANSITIONAL_LIMITATION
- ENVIRONMENTAL_RESTRICTIONS
- METERING_TELEMETRY
- UNIT_TESTING
- SHORT_TERM_USE_LIMIT_REACHED
- RIMS_TESTING
- ANNUAL_USE_LIMIT_REACHED
- MONTHLY_USE_LIMIT_REACHED
- TECHNICAL_LIMITATIONS_NOT_IN_MARKET_MODEL
- OTHER_USE_LIMIT_REACHED
- RIMS_OUTAGE
- UNIT_SUPPORTING_STARTUP
- RTU_RIG
- ICCP

CAISO Curtailment Natures-of-Work

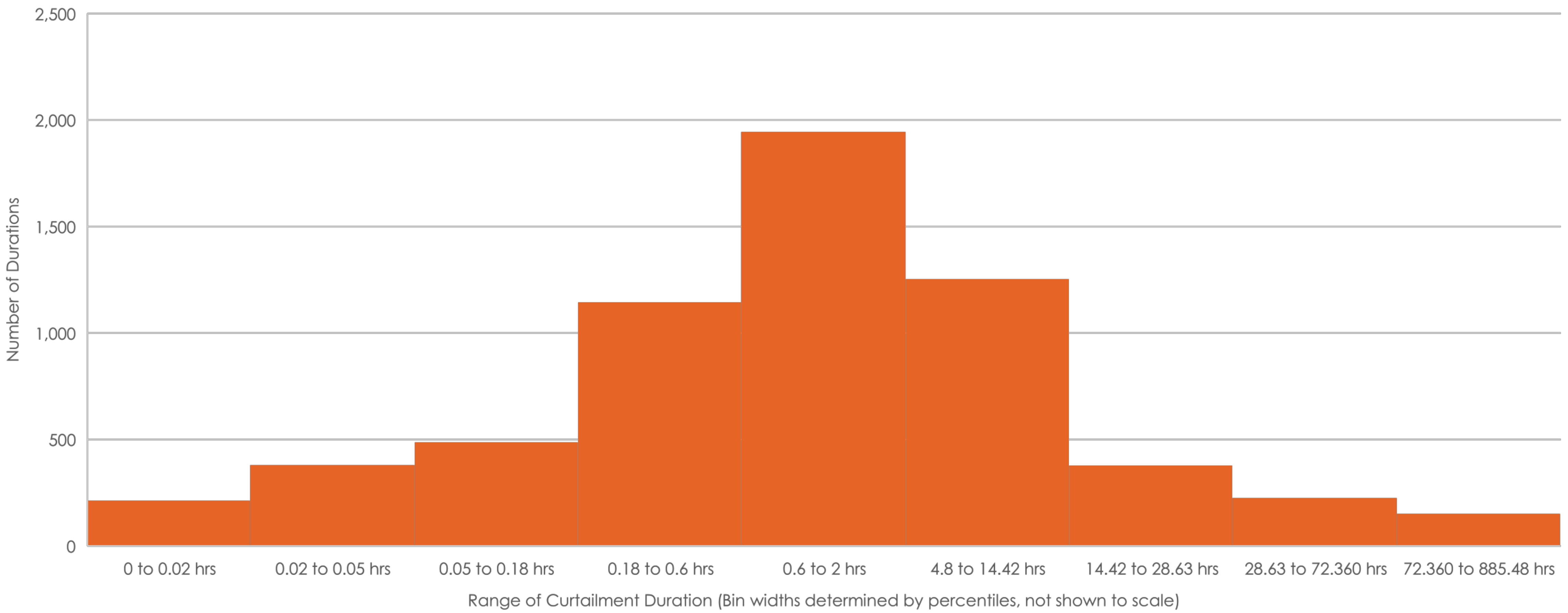
Forced Outages:

- AMBIENT_DUE_TO_FUEL_INSUFFICIENCY
- AMBIENT_DUE_TO_TEMP
- AMBIENT_NOT_DUE_TO_TEMP
- ANNUAL_USE_LIMIT_REACHED
- ENVIRONMENTAL_RESTRICTIONS
- ICCP
- METERING_TELEMETRY
- MONTHLY_USE_LIMIT_REACHED
- NEW_GENERATOR_TEST_ENERGY
- OTHER_USE_LIMIT_REACHED
- PLANT_MAINTENANCE
- PLANT_TROUBLE
- RIMS_OUTAGE
- RIMS_TESTING
- RTU_RIG
- SHORT_TERM_USE_LIMIT_REACHED
- TECHNICAL_LIMITATIONS_NOT_IN_MARKET_MODEL
- TRANSITIONAL_LIMITATION
- TRANSMISSION_INDUCED
- UNIT_SUPPORTING_STARTUP
- UNIT_TESTING

Planned Outages:

- AMBIENT_DUE_TO_FUEL_INSUFFICIENCY
- AMBIENT_DUE_TO_TEMP
- AMBIENT_NOT_DUE_TO_TEMP
- ENVIRONMENTAL_RESTRICTIONS
- METERING_TELEMETRY
- NEW_GENERATOR_TEST_ENERGY
- PLANT_MAINTENANCE
- PLANT_TROUBLE
- RIMS_OUTAGE
- RTU_RIG
- SHORT_TERM_USE_LIMIT_REACHED
- TRANSITIONAL_LIMITATION
- TRANSMISSION_INDUCED
- UNIT_SUPPORTING_STARTUP
- UNIT_TESTING

Number of Curtailments by Duration (All Causes)



Selecting Curtailments

Natures-of-Work Included (when paired with Outage Type “FORCED”):

- PLANT_TROUBLE
- NEW_GENERATOR_TEST_ENERGY
- TRANSITIONAL_LIMITATION
- ENVIRONMENTAL_RESTRICTIONS
- METERING_TELEMETRY
- UNIT_TESTING
- SHORT_TERM_USE_LIMIT_REACHED
- RIMS_TESTING
- ANNUAL_USE_LIMIT_REACHED
- MONTHLY_USE_LIMIT_REACHED
- TECHNICAL_LIMITATIONS_NOT_IN_MARKET_MODEL
- OTHER_USE_LIMIT_REACHED
- RIMS_OUTAGE
- UNIT_SUPPORTING_STARTUP
- RTU_RIG
- ICCP

Selecting Curtailments

Dates:

- Only used full months between July 2021 and November 2023
- Resources with startup dates after July 2021 truncated to first full month

Approach to Estimating EFOR

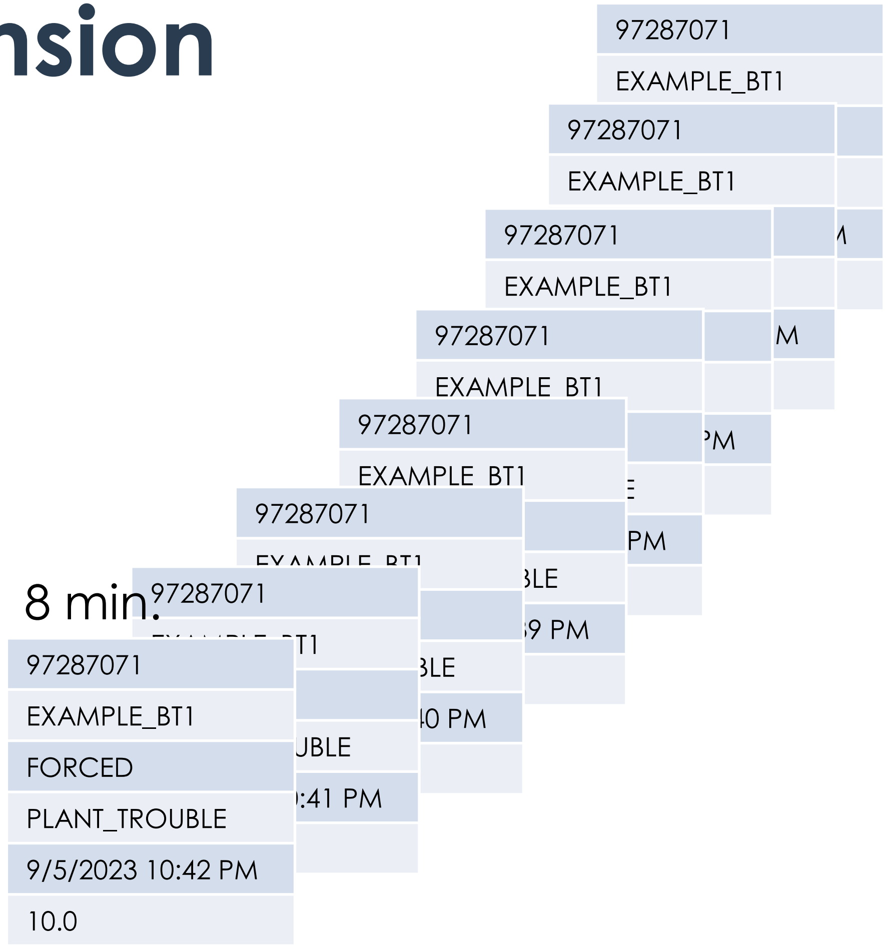
1. Download all available CAISO Prior Trade-Day Curtailment Reports
2. Merge all reports into a single table
3. Join curtailments table with Master Capability List to identify resource types and apply Net Dependable Capacities
4. Filter curtailments for battery resources
5. Filter curtailments for “FORCED” outage types and selected natures-of-work

Approach to Estimating EFOR

6. Expand table into discrete time blocks of equal duration based on curtailment start and end times
7. Remove duplicate curtailment records (same Outage MRID and time)
8. Calculate disaggregated Equivalent Forced Deration Hours as Curtailment MW * time block in hours / Net Dependable Capacity
9. Aggregate by Resource ID and Month
10. Calculate Equivalent Forced Outage Rate as EFDH / (Hours in Month – Planned Outage Hours)

Curtailment Time Block Expansion

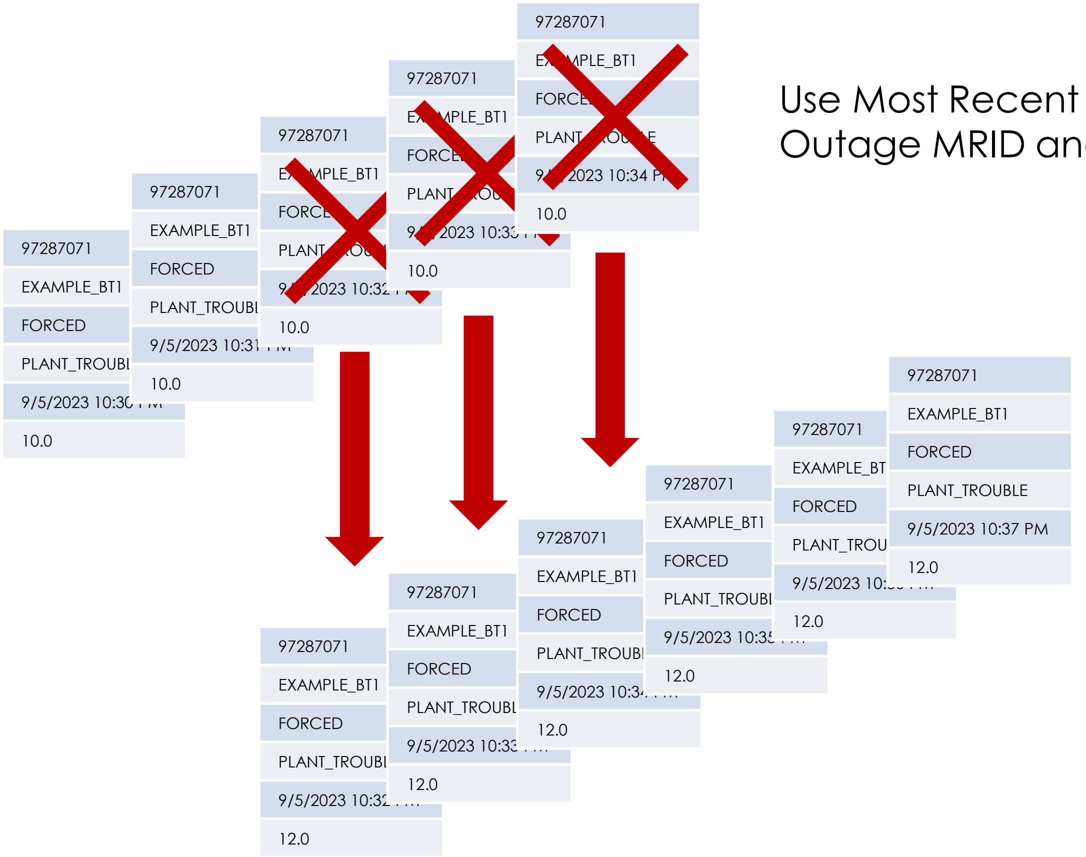
FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT START DATE TIME	9/5/2023 10:35 PM
CURTAILMENT END DATE TIME	9/5/2023 10:43 PM
CURTAILMENT MW	10.0



Handling Overlapping Curtailment Reports

FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT START DATE TIME	9/5/2023 10:30 PM
CURTAILMENT END DATE TIME	9/5/2023 10:36 PM
CURTAILMENT MW	10.0

FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT START DATE TIME	9/5/2023 10:32 PM
CURTAILMENT END DATE TIME	9/5/2023 10:38 PM
CURTAILMENT MW	12.0

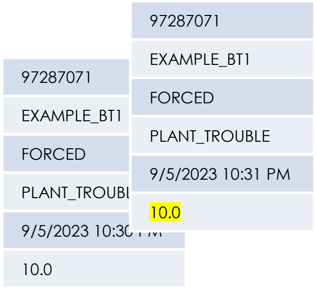


Use Most Recent Report for each Outage MRID and Datetime

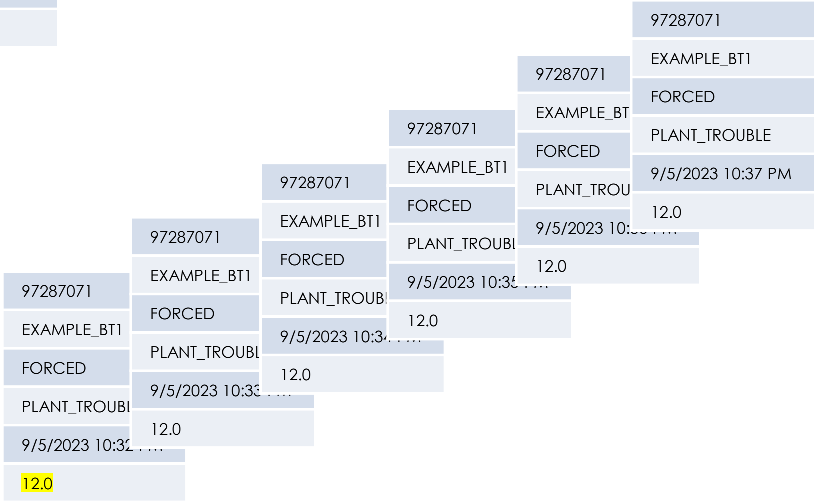
Handling Overlapping Curtailment Reports

FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT START DATE TIME	9/5/2023 10:30 PM
CURTAILMENT END DATE TIME	9/5/2023 10:36 PM
CURTAILMENT MW	10.0

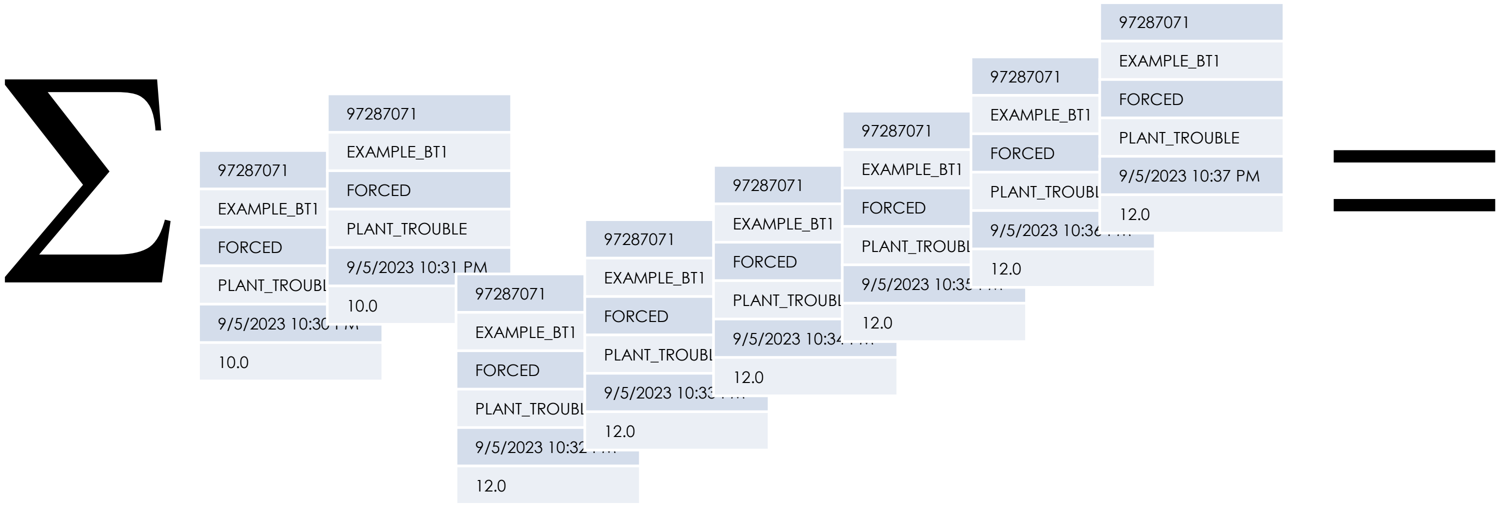
FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT START DATE TIME	9/5/2023 10:32 PM
CURTAILMENT END DATE TIME	9/5/2023 10:38 PM
CURTAILMENT MW	12.0



Curtailment MW may vary throughout duration



Aggregating Curtailment Time Blocks



FIELD	VALUE
OUTAGE MRID	987654321
RESOURCE ID	EXAMPLE_BT1
OUTAGE TYPE	FORCED
NATURE OF WORK	PLANT_TROUBLE
CURTAILMENT DURATION	8 minutes
EFDH	0.0153 hours

Example Net Dependable Capacity = 100 MW

EFDH = (10 MW * 2 minutes + 12 MW * 6 minutes) / 100 MW * (1hr / 60 minutes)

Calculating Monthly EFOR

GADS Definition: $EFOR = \frac{FOH+EFDH}{FOH+SH+Sync\ Hrs+Pumping\ Hrs+EFDHRS}$

$$FOH = Forced\ Outage\ Hrs$$

$$EFDH = Equivalent\ Forced\ Deration\ Hrs = \frac{Deration\ Hrs \times Size\ of\ Reduction}{Net\ Maximum\ Capacity}$$

$$SH = Service\ Hrs$$

$$EFDHRS = Equivalent\ Forced\ Deration\ Hrs\ during\ Reserve\ Shutdowns$$

Applied Approximation: $\frac{\frac{Deration\ Hrs \times Size\ of\ Reduction}{Net\ Dependable\ Capacity}}{Month\ Hrs - Equivalent\ Planned\ Deration\ Hrs}$

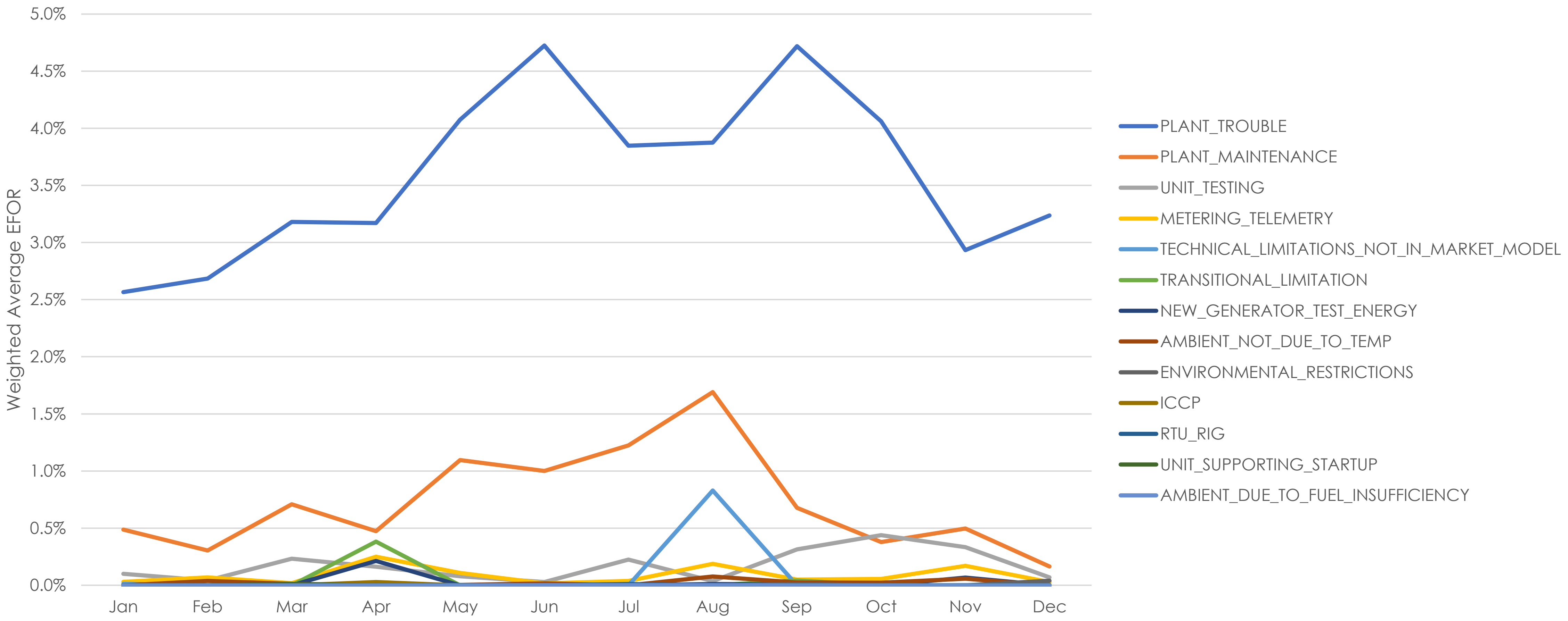
Limitations and Notes

- Reserve shutdown and service hours are unknown
- Charging hours are unknown
- Forced Outage Hours = Equivalent Forced Deration Hours when Size of Deration = Net Maximum Capacity (i.e., 100% deration)

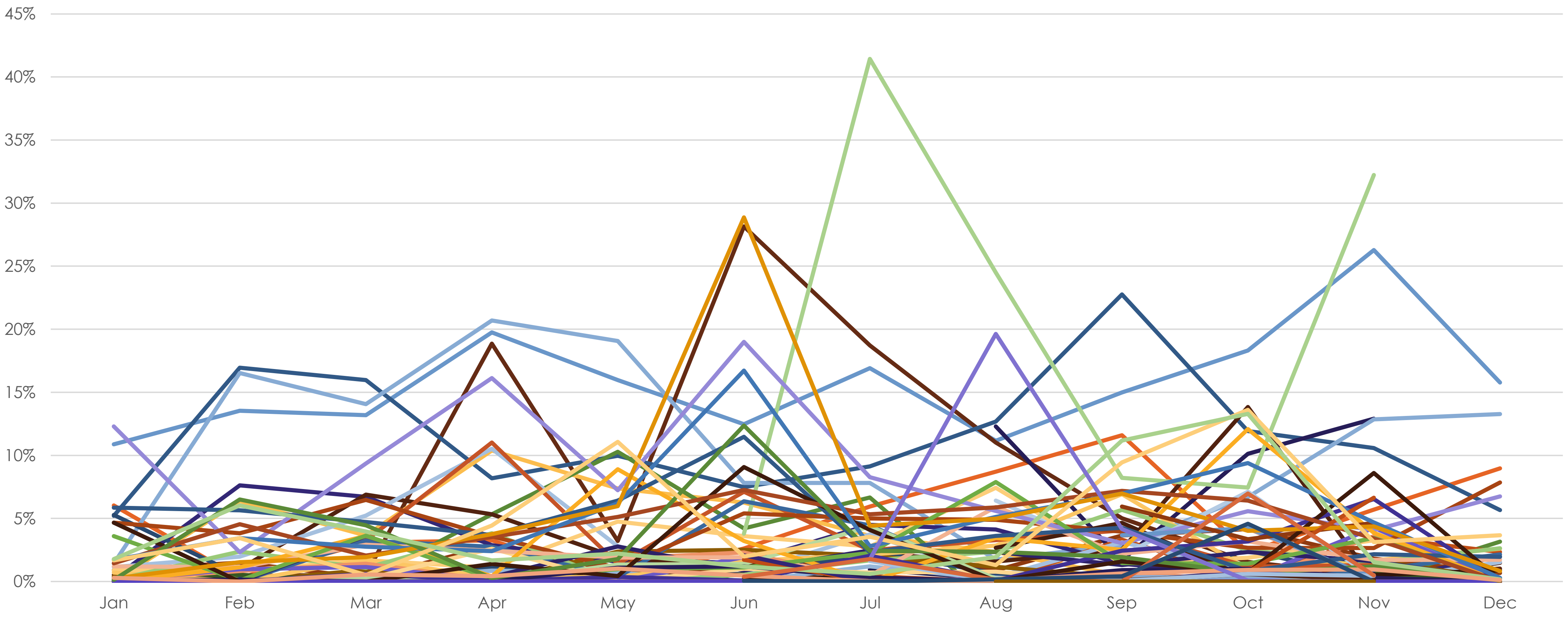
UFOR for Battery Energy Storage Systems

Results

Capacity-Weighted Average EFOR by Nature-of-Work and Month



EFOR by Resource and Month



Conclusions

- Wide variation in EFOR by resource
- Seasonal variation in EFOR visible with higher outage rates in summer than winter
- EFOR values lower than expected due to issues in calculating denominator

UFOR for Battery Energy Storage Systems

Reiterating Remaining Issues

California Public Utilities Commission

Remaining Issues for Storage UCAP

- EFOR Denominator
  - Where to find or how to estimate Reserve Shutdowns and Charging Hours?
  - Assume 4 hours or other fixed charging time each day?
  - Expect EFOR to increase with any change.
- Cause Code Equivalency
  - Do any curtailments marked "Planned" count toward Forced Outage Rate?
  - Which Nature-of-Work values should be included in EFOR numerator and denominator?
- Resource Aggregation
  - Is aggregation necessary, or are resource-level monthly EFOR preferrable?

Remaining Issues for Storage UCAP

- All results are preliminary
- We request stakeholder feedback on these issues and any other concerns

Questions?

For more information:

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PG&E Track 1 Proposals

February 14, 2024

Presenter: Luke Nickerman

Agenda

- Unforced Capacity (UCAP)
  - Concept and Incentives
  - Principles

- Use PCIA benchmark as the recoverable cost for CAM replacement cost to address potential cost shifts

- Clarifications on Import Allocation Rights for Resource-Specific Solar and Wind Resources

UCAP Concept and Incentives

- **Represents a qualifying capacity value that internalizes the incidence of forced outages and impacts of ambient derates**
  - Full UCAP includes both
  - UCAP-lite only includes ambient derates (some resource owners already derate plants for this)
  - Ideally is an improved estimate of what resources are able to deliver

- **Types of outages vary**
  - Forced and urgent outages are unpredictable
  - Ambient derates are very predictable

- **If implemented well, provides an incentive for resource owners to perform plant maintenance that leads to greater plant reliability and availability**
  - Typically this is a long-term incentive (if methodology uses several years of data)
  - Getting the incentive right can be challenging, e.g. if a resource performs extensive work to improve reliability, the impact to the QC value can take years to be fully reflected, muting the incentive to do the work
  - What to do about ambient derate profile (one monthly value? hourly?)
  - In some cases, the incentive may not exist, e.g. the plant plans to retire

- **PG&E included CAISO's RA Enhancements UCAP proposal as an attachment to PG&E's CPUC proposals**
  - Sixth Revised Straw Proposal – December 2020
  - That proposal has features that may be worth considering, e.g. resource-level methodology
  - Other features that haven't yet been developed (data collection) or likely don't work for slice-of-day (supply cushion methodology)

UCAP Principles

- **Simultaneous CAISO / CPUC adoption and implementation**
  - Avoids the use of significantly different qualifying capacity ("QC") values between the Commission and CAISO and complications that could stem from those differences
- **Adopted in conjunction w/ PRM adjustment**
  - Reflects shift of resource outage uncertainty from PRM to QC value
- **Adopted in conjunction w/ changes to RAAIM**
  - RAAIM is a penalty
  - Underlying incentive is more short-term
  - Need to sort out what changes, if anything
- **Be at the resource-specific level**
  - Aggregated values lessens the incentive to maintain the resource
  - Depending on mix of resources in a group, QC value distortions could be significant
- **Use public data**
  - Ideally resource owners can estimate a QC value
- **Feature reasonable timing for implementation**
  - 2025 RA compliance year would be much too soon when slice-of-day is being fully implemented for the first time

Use PCIA benchmark as the recoverable cost for CAM replacement cost to address potential cost shifts

- PG&E manages cost-allocation mechanism (CAM)-eligible resources on behalf of all customers in the service territory and departed load customers receive the RA benefits through RA requirement reductions
- Managing the resources involves providing substitution capacity to CAISO when a resource is on outage (all customers are responsible for paying for this capacity)
- ED RA report prices are used as the recoverable cost for CAM replacement cost when a CAM resource is on outage or otherwise unable to be shown and the IOU uses a resource from its portfolio to replace the resource (per the RA Filing Guide)
- However, the PCIA benchmark is required to be used when the IOU retains that resource for substitution (per D.19-10-001)
- Because RA report prices differ from the PCIA benchmark prices, cost shifts occur when PCIA benchmark prices are higher or lower than RA report prices

Proposal: Use the PCIA benchmark price as the recoverable cost for CAM replacement cost to align with the cost to IOU bundled customers to retain the resource for substitution

Example of Cost Shift

- 100 MW Resource -> is on outage for month of February and IOU substitutes with resource from IOU portfolio
- IOU retains the resource for $15.23/kW-month or $1,523,000 ($15.23/kW-month * 100 MWs * 1,000)[1]
- IOU can recover costs of the replacement capacity at $4.98/kW-month or $498,000 ($4.98/kW-month * 100 MWs * 1,000)[2]
- Cost shift to bundled customers = **$1,025,000** ($1,523,000 - $498,000)

A	Example resource size (MWs)	100
B	Cost to retain resource ($/kW-month)	$15.23
C	Cost to replace resource ($/kW-month)	$4.98
D	Total cost to retain (100 * 15.23 * 1,000)	$1,523,000
E	Total cost to replace (100 * 4.98 * 1,000)	$498,000
F	Cost shift to bundled customers (D - E)	$1,025,000

Sources:

1. Calculation of the Market Price Benchmarks for the Power Charge Indifference Adjustment Forecast and True Up, October 2, 2023, p. 2, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-mpb-2023-2024-final.pdf
2. 2020 Resource Adequacy Report, dated April 2023, p. 26, available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2021-ra-report---update-011624.pdf

AReM
Alliance for Retail Energy Markets

Proposal for "Effective" Capacity on CAISO Supply Plans

February 14, 2024

CPUC Track 1 RA Workshop

R.23-10-011

Background: PRR 1280

- CAISO Proposed Revision Request ("PRR") 1280 created different treatment of Demand Response ("DR") resources in Commission and CAISO RA Programs
  - Certain DR credits Commission allocates to LSEs are not credited by CAISO
- August 2023 CAISO capacity procurement mechanism ("CPM") event
  - AReM members compliant with Commission requirements were assessed CPM cost responsibility because of treatment of DR resources
- Working within CAISO RA Working Group to resolve issue, but risk of CPM cost responsibility remains

Background: "Effective" Capacity

- Investor-owned utilities ordered in emergency reliability rulemaking (R.20-11-003) to begin procurement of additional summer capacity on behalf of all load-serving entities ("LSE") in their territories
  - Called "effective" capacity or "effective" planning reserve margin
- Treatment was extended in D.23-06-029 for summer 2024 and 2025
- Procurement can include RA-eligible resources
- Capacity is paid for through cost-allocation mechanism ("CAM")

Problem: CPM Cost Shift

- LSEs at risk of CPM cost responsibility because of PRR 1280
- IOUs report RA-eligible "effective" capacity on CAISO supply plans
  - Reduces IOU cost responsibility risk for CPM events
- Cost shift to electric service provider ("ESP") and community choice aggregator ("CCA") customers
  - Customers pay for the "effective" capacity through the CAM
  - Receive no benefit for CPM cost responsibility

AReM Proposal

- Allocate RA-eligible “effective” capacity to ESPs and CCAs for reporting on CAISO supply plans
- Use existing CAM mechanism to perform the allocation
- Would only impact CAISO reporting; no allocations of credits for Commission RA compliance

The Following Slides Were Not Presented at the Workshop on February 14, 2024.

These topics will be covered at a future RA OIR Track 1 Workshop, to be noticed shortly.

The Public ADVOCATES OFFICE

Residual Capacity Auction Proposal

R.23-10-011

February 2024

Problem Statement

1. System RA prices at historic levels, do not reflect going forward fixed costs
2. Market failures due to information asymmetry, bounded LSE rationality, and market power issues
3. No mechanisms for Commission to:
   a. Weigh alternatives against exceptionally high prices; or,
   b. Procure capacity to make up LSE deficiencies → everyone at risk
4. LSE proliferation increases competitiveness of buyers' game of musical chairs
5. Single monthly capacity product → quarterly/annual/multi-year strips

Solution: Residual Capacity Auction (RCA)

1. Extend the authority of a Local RA CPE to procure for system RA deficiencies
2. Aggregated system RA deficiencies for May-Sept sent to the Operator of the RCA (ORCA) for procurement
   a. LSEs will be able to submit a system RA deficiency waiver if they made good faith and commercially reasonable efforts, but no capacity available below the deficiency penalty price
3. RCA is a reverse blind auction, will procure least-cost capacity, bidders receive their bid price

Solution: RCA

4. Products are RA Only capacity and RA Import capacity for May-Sept, using *pro forma* contracts
5. RCA will run for YA deficiencies and as necessary for May-Sept MA deficiencies (maximum six times per year)
6. Costs and credits allocated to deficient LSEs on a proportional volumetric deficiency slice-MW basis
7. Deficient LSEs will be charged at the average cost of the procured portfolio

Benefits I

Acts as a circuit-breaker and protects against market failure:

Issue	How RCA Addresses it
Information asymmetry: LSEs lack information about suppliers costs, LSE proliferation means suppliers can game solicitations.	Single buyer with high volume of bids and high visibility into market costs
Bounded LSE rationality: LSEs acting in their own rational interests lead to inefficient market solutions. High LSE willingness to pay and perception of scarcity becomes a contagion, pushing up prices.	Single buyer can make determination of true market scarcity, can assess market power and bid competitiveness
Market power: Suppliers able to extract high rents without commensurate improvement in reliability.	Waiver reduces supplier power in bilateral negotiations, single buyer increases bidder competition

Benefits II

- Single buyer structure disrupts collective market failures
- ORCA can select reasonable bids and assess alternatives in event of un-competitive RCA results
- When true scarcity exists, the status quo leads to high prices with no change in volume (rent transfer to suppliers)
  - CPUC has not adopted “reliability at any cost” standard
  - RCA allows CPUC to weigh tradeoffs between costs and reliability

Benefits III

- RCA provides mechanism to cure CPUC deficiencies and force deficient LSEs to pay for their share
- Ensures reliability and mitigates against CAISO backstop
  - LSEs can currently make rational choice to accept penalties
- Eff. PRM is only CPUC tool to backstop LSE deficiencies
  - But costs socialized among <u>all</u> LSEs, not deficient ones
- Long LSEs can optimize surplus by bidding into RCA
- Hypothetical: snap fingers and use RCA for 2024--up to **86% savings** possible (given October 2023 prices)

Costs

- Staff to run the RCA
- Commission Staff to process possible increase in system RA waiver requests
- If IOUs are the ORCA, contract assignment will require a debt equivalence adder
- Requires LSEs to finalize bilateral procurement sooner
- Procurement Costs

Cost Allocation

- Administrative costs allocated by load-share to all CPUC LSEs
- Procurement costs allocated to deficient LSEs
  - Cost share proportional to total slice deficiencies

Table 1: RA Deficiency Responsibility Example

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
LSE 1 Deficiency (MW)						20														10	10			
LSE 2 Deficiency (MW)																			50	90				
Aggregate LSE Deficiencies (MW)						20													50	100	10			

- LSE 1 = 40 MW. LSE 2 = 140 MW. Aggregate deficiency = 180 MW
- LSE 1 pays 40/180 = 22.2% of RCA procurement costs. LSE 2 pays 77.8%

Who is the ORCA?

- Recommend **SCE-CPE**
  - SCE has higher credit rating
  - Can act as counterparty to RCA contracts
  - Already has procurement function for Local RA CPE
  - As a scheduling coordinator, can file supply plan with CAISO
  - Extends an existing authority, will not require statutory authorization
  - PRG will have visibility into bid stacks and can advise SCE-CPE
- ORCA should **not** be the CAISO

Timeline Considerations

Year-Ahead

- Mid-Oct: ORCA prepares auction, conducts initial outreach;
- Oct 31: LSEs and CPEs make YA showings to the CPUC and CAISO;
- First week Nov: RCA receives capacity offers from auction participants and procurement targets from the Commission;
- Mid-Nov: RCA sends shortlist notifications and begins contract executions;
- Late-Nov: RCA contract executions complete and RCA files supply plans to Commission and CAISO.

Timeline Considerations

Month-Ahead

- LSE showing deadline moved up by 15 days to 60 days ahead of start of compliance month
- 15 calendar days to solicit and execute offers by 45 days ahead
- Durable *pro forma* contract for a commodity RA Only product that negates/minimizes negotiations is crucial to facilitating ambitious timelines

Image credit: Christopher Michel under

RA Compliance and Penalty Structure Proposals

Resource Adequacy Track 1 Proposal Workshop

February 14, 2024

The RA Market is Extremely Tight

Makes it difficult, if not impossible, for all LSEs to comply with their obligations

CalCCA stack analysis estimates system RA supply deficiency of 894 MW for September 2024

LSEs express challenges finding RA - responses to RFOs down, responses often do not contain products needed, offers not in time to be shown, etc.

It will take time for new capacity to come online to build sufficient excess into the RA supply stack

Two Modifications Needed to the RA Compliance and Penalty Structure

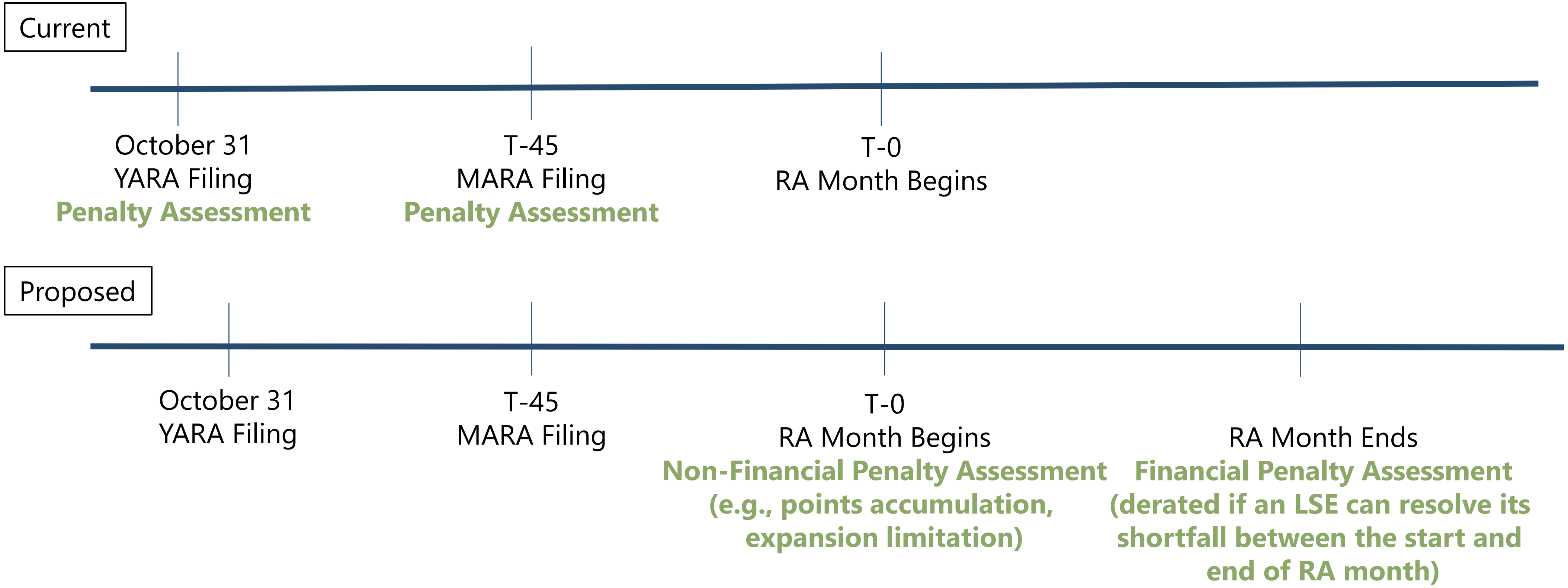
1. Modify the timing of penalty assessments by extending the year-ahead RA (YARA) and month-ahead RA (MARA) cure periods

Allows for access of new and existing capacity that becomes available between the showings and the RA month (e.g. an IRP resource that comes on-line August 1st provided reliability in August even though it was not on-line by June 15th to be in an RA showing)

2. Adopt a Temporary Waiver Process for System and Flexible RA to Ensure a Smooth Transition through the Initial SOD Compliance Years

Provides relief to LSEs who demonstrate procurement efforts consistent with a high standard in recognition of supply constraints coupled with regulatory uncertainty

Modify the Timing of Penalty Assessments by Extending the YARA and MARA Cure Periods



Adopt a Temporary Waiver Process for System and Flexible RA

- System and Flexible RA waiver from **2025 through 2027***
- LSEs would be required to demonstrate procurement efforts taken to justify the Commission granting a waiver
- Depending on the justification, LSEs would be eligible for a **full or partial waiver**
  - Full waiver = waiver of financial penalties and non-financial penalties (e.g., points accumulation and expansion limitation)
  - Partial waiver = waiver of non-financial penalties only

* CalCCA does not object to implementing the waiver in 2024 consistent with SCE's proposal

Discretionary Waiver Criteria

Partial Waiver

- Demonstration of tight market conditions
  - LSE reasonably and in good faith solicited bids, including participation in IOU solicitations and bi-lateral market, and
  - Despite having actively pursued all commercially reasonable efforts, LSE either:
    - Received no bids less than 3x Penalty + CPM Soft Offer Cap rounded up to the nearest ten ($40 per kw-month), or
- Received bids that included unreasonable terms and/or conditions.

Full Waiver

- **Highly constrained market conditions:** In addition to the criteria above, LSE received insufficient bids and/or bilateral offers to satisfy its system and/or flex obligations
- **PPA delay:** COD delays contributed to LSE's need for waiver
- **SOD Waiver:** LSE made reasonable efforts to meet the SOD compliance obligations but were unable due to SOD implementation issues

RA Import Bid Rules Proposal

Resource Adequacy Track 1 Proposal Workshop

February 14, 2024

Background (1 of 2)

- D.20-06-028 modified eligibility rules for non-resource specific RA imports such that the energy must be bid into the CAISO between negative $150/MWh and $0/MWh or self-scheduled during the availability assessment hours

- In R.21-10-002, CalCCA proposed to modify the import RA bid cap to allow for reasonable recovery of costs
  - Devise a “no higher than” bid price which reflects the costs the typical marginal import resource (i.e., combustion turbine peaker) would expect to incur
  - Total Cost = Fuel + GHG + Variable O&M
    - GHG and Variable O&M are the lesser impact and are relatively stable
    - Gas price volatility can drive significant variation in the total cost
      - Develop tiered bid caps based upon different gas prices

Background (2 of 2)

- D.23-06-029 rejected CalCCA's proposal, stating:

  "[T]here is <u>insufficient information</u> to determine whether CalCCA's proposal would necessarily increase the volume of imports, rather than merely reducing the [RA] price of imports"

  and

  "<u>Should information arise</u> as to why the current RA import bidding requirements warrant modification, Energy Division Staff should present that information to the Commission and stakeholders for consideration"

- <u>New information</u> regarding the availability of RA imports warrants reconsideration of CalCCA's proposal to ensure out-of-state resources have the right incentives to provide RA capacity to California

CAISO RA showings data shows a declining trend of RA imports

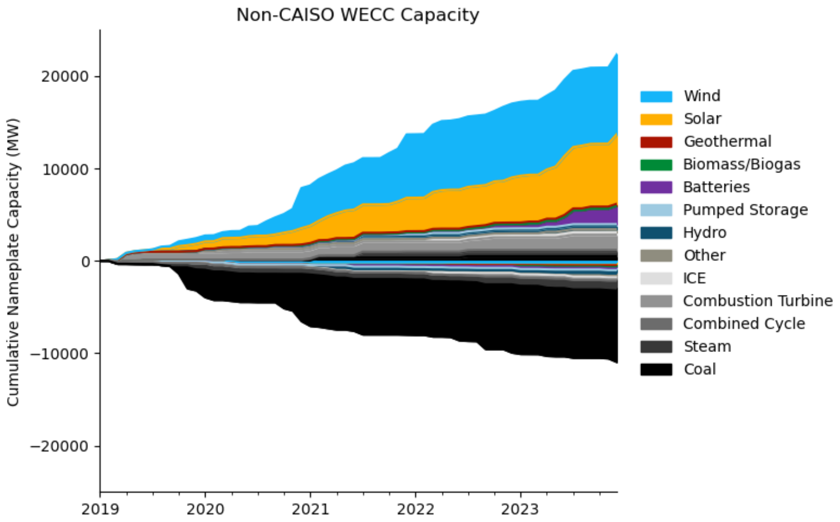
Since the Commission adopted the existing RA import bidding rules in 2020, YA imports have declined significantly

Year-Ahead (September)						
Year	Non-Resource Specific Imports	Resource Specific Imports	Total RA Shown	MWs of Non-Resource Specific Imports	MWs of Resource Specific Imports	Total RA Imports
2019	9.20%	3.63%	43,996	4,046	1,599	5,645
2020	9.97%	3.65%	42,313	4,218	1,545	5,763
2021	5.18%	5.00%	41,997	2,177	2,101	4,278
2022	3.01%	5.06%	43,041	1,294	2,179	3,473
2023	3.27%	5.33%	45,802	1,499	2,442	3,941

Month-Ahead September						
Year	Non-Resource Specific Imports	Resource Specific Imports	Total RA Shown	MWs of Non-Resource Specific Imports	MWs of Resource Specific Imports	Total RA Imports
2019	13.91%	3.23%	50,111	6,970	1,617	8,587
2020	13.17%	4.19%	48,973	6,450	2,050	8,500
2021	8.75%	4.62%	47,936	4,196	2,213	6,409
2022	7.99%	4.68%	49,201	3,932	2,304	6,236
2023	7.22%	4.77%	53,087	3,833	2,530	6,363

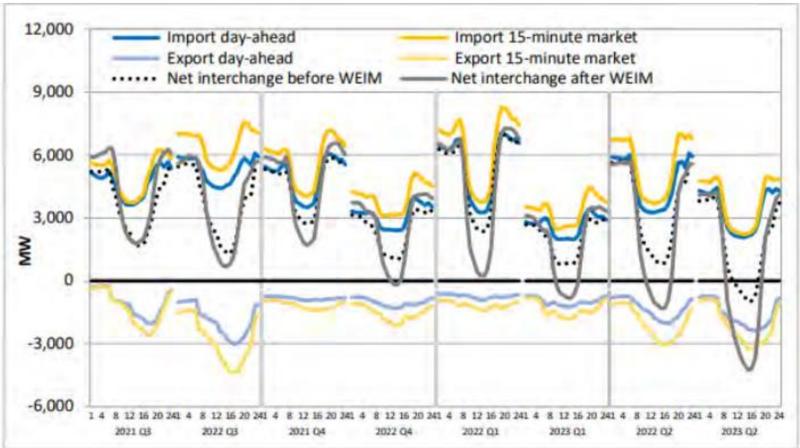
Capacity characteristics are changing throughout the West

Non-CAISO WECC Capacity



Source: CalCCA analysis of EIA 860M through December 2023

Average Hourly Net CAISO Interchange by Quarter



Source: DMM 2023 Second Quarter Report on Market Issues and Performance

Significant coal retirements were replaced by intermittent resources like wind and solar.

Exports increased in the middle of the day. Imports have decreased in the evening hours.

Under these conditions, we should be seeking to accommodate imports by not requiring energy market losses

Suppliers indicate inability/unwillingness to sell import RA under current rules

- **<u>BPA Proposal:</u>** *"The ability to economically bid would incentivize Bonneville to potentially commit more of its surplus generation to participate in the California RA market, increasing the RA supply, and ultimately putting downward pressure on the RA prices and the cost to California consumers"*

- **<u>SJCE Declaration:</u>** *"Sellers of import RA have shared their unwillingness to flow power from north to south into California because of the price differential between locations; it is not economically feasible to sell the supply as import RA under the current rules."*

Updated analysis shows anticipated energy market losses have increased since 2022

Percent of AAH Where CAISO MCE is Less Than the Estimated Cost @ 12 MMBTU/MWh									
	2022					2023			
	June	July	August	September		June	July	August	September
Low Gas Price	47%	48%	5%	29%		96%	38%	40%	89%
High Gas Price	91%	91%	56%	65%		100%	65%	72%	99%

Loss Where Example Peaker Generation Cost is Greater Than CAISO MCE ($/MWh)									
	2022					2023			
	June	July	August	September		June	July	August	September
Low Gas Price	$ 2.31	$ 2.16	$ 0.07	$ 0.89		$ 5.81	$ 1.70	$ 0.94	$ 4.19
High Gas Price	$ 8.40	$ 8.55	$ 2.79	$ 4.70		$ 12.48	$ 4.77	$ 4.27	$ 9.25

In totality, these factors have led CalCCA to recommend that the Commission...

Reconsider CalCCA's proposal to ensure out-of-state resources have the right incentives to provide RA capacity to California

TRACK 1 RA PROPOSAL

BACKGROUND

- The CPUC issued Decision (D.) 23-06-029 which is the Decision Adopting Local Capacity Obligations for 2024-2026, Flexible Capacity Obligations for 2024, and Program Refinements in Rulemaking (R.) 20-01-002 (Resource Adequacy (RA)) on July 5, 2023.
- CEERT, the Council, Leapfrog Power, Inc., OhmConnect, Inc., CPower and Enel X North America, Inc. submitted a Joint Application for Rehearing (AFR) and Joint Motion for Partial Stay of this decision on August 4, 2023.
- The CPUC issued an Order Denying the AFR and Motion on December 18, 2023 (D.23-12-038).

DR Rule Changes in D.23-06-029

- D.23-06-029 made numerous changes to RA demand response (DR) rules, particularly as it pertains to third-party DR providers (DRPs). Specifically, it did the following:
  - Reversed the present limitation on Reliability DR Resources (RDRR) as an RA resource during system emergencies only,
  - Eliminated Transmission Loss Factor (TLF) Adder and Planning Reserve Margin (PRM) Adder,
  - Adopted unworkable Proxy DR availability requirements, and
  - Introduced a new and untenable risk to third-party DR resources by derating their qualifying capacity (QC) values outside of the existing QC valuation process.

CEERT and the Council Track 1 RA Proposal

- In Track 1 of this proceeding, the CPUC should direct a full evaluation of current RA DR rules and the merits of any other CPUC RA DR rule changes that the CPUC is planning to make.
- The CPUC should give parties an opportunity to develop an evidentiary record so that they can be heard on the impacts to DR and DRPs of the changes made in D.23-06-029.
- The CPUC should permit parties to submit proposals that identify, limit and reverse negative effects of these rules.
- There is currently no other venue at the CPUC for parties to address these DR issues, so they must be addressed in the RA proceeding.

Monthly SOD PRM: 2021 vs. 2023 IEPR Peak Managed Load

Mounir Fellahi
Energy Resource Modeling Team, Energy Division
February 28th, 2024

Background

- Parties requested more information regarding use of the new IEPR and effects of exceedance on the resulting PRM.
- Staff conducted some sensitivities around these questions and present the following results
- This is not a proposal to change PRM each year.
- It may highlight the chance to stabilize PRM if we stabilize exceedance values across the three peak months of the summer.
- The new IEPR is a reduction in July, August and September months, meaning using the new IEPR with the prior portfolio requirements results in a larger PRM.

SOD PRM: 2021 IEPR vs. 2023 IEPR Managed Peak Demand

- The table compares SOD PRM using the managed peak load from the 2021 IEPR and the 2023 IEPR; the PRM for the 2023 IEPR utilizes the managed peak load forecast for 2025, not 2024.

Month	PRM using IEPR 2021	PRM using IEPR 2023 (With 2025 Managed Load)
July	29.27%	31.38%
August	25.81%	34.17%
September	15.43%	22.81%

SOD PRM: Monthly Exceedance versus only September Exceedance

- The table compares SOD PRM using the managed peak load from the 2021 IEPR. The second column displays PRM with Monthly Exceedance, and the last column applies September Exceedance to July and August.

Month	PRM with Monthly Exceedance	PRM with Sep Exceedance
July	29.27%	20.46%
August	25.81%	19.18%
September	15.43%	15.43%

SOD PRM: Comparing 2021 IEPR and 2023 IEPR with September Exceedance Values

- The table compares SOD PRM using the managed peak demand from the 2021 IEPR and the 2023 IEPR, while applying the September exceedance values to July and August. The second column shows the PRM with Monthly Exceedance based on the 2021 IEPR data, and the last column shows the PRM with September Exceedance applied to July and August using the 2023 IEPR data.

Month	PRM with Sep Exceedance - IEPR 2021	PRM with Sep Exceedance - IEPR 2023
July	20.46%	22.77%
August	19.18%	26.21%
September	15.43%	22.81%

Thank you.

Workshop presentations, recording, and related materials will be posted in the upcoming weeks on the Energy Division Resource Adequacy website under the page, "Resource Adequacy History."

Any questions on this workshop can be directed to eric.dupre@cpuc.ca.

California Public Utilities Commission